

# Power to the Markets

By Dillon Smith  
& Sean Ridley





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# Executive Summary

*'I do not see the Government's task as being to try and plan the future shape of energy production and consumption'* – Nigel Lawson, Energy Secretary, 1982

*'We are now entering a world in which green power need not be subsidised'* – Greg Clark, Energy Secretary, 2019

*'The policy of this Government is that it is time for the British people to also own things again and build things again'* – Ed Miliband, Energy Secretary, 2024

Cheap energy is the foundation upon which growing economies are built. Which is awful news for Britain.

Our country has among the highest industrial energy prices in the world. And many of the Government's policies are making things worse rather than better.

To date, the debate over the cost of energy has revolved around the Net Zero mandate, and the respective merits of fossil fuels, nuclear and renewables. This debate is certainly important. But it obscures a more fundamental shift in the nature of the British energy market – namely, that it is no longer much of a market at all.

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Ed Miliband has, of course, been crystal clear that he wants the energy market to be controlled, and if possible owned, by the state. He has set up Great British Energy, a new energy investment outfit. He has mandated that the grid be almost completely decarbonised by 2030, primarily via an enormous expansion of offshore wind and the accompanying subsidy regime. He has not just approved and subsidised but taken co-ownership of a massive new nuclear plant. He has mandated that grid connections should be prioritised according to the decisions of civil servants rather than the market. In short, the Government seems intent on planning out in exquisite detail exactly how our energy system should look – and sticking consumers with the bill for all of it.

But as elsewhere across the economy, it is not just Labour who are behind this shift away from the market. The trend towards ever greater state direction of the power market began under the Conservatives – preaching the gospel of markets, but in practice entrenching central planning, for example via the adoption by Theresa May of Miliband's energy price cap.



We argue in this paper that the core problem with Britain's energy market, and the abiding reason costs are so high, is not that it is too green, or not green enough, but that it has steadily squeezed out market mechanisms and price signals. We need to correct this urgently – not to bring prices down today, but to save the market of tomorrow.

It is hugely underappreciated in our current debate that we will soon be entering a new era for our power market – one driven by demand growth, not decarbonisation.

While this country has built an impressive amount of new capacity in the last 15 years, it has primarily been replacing existing generation – first coal, and now gas and nuclear. Indeed, total demand on the system has been declining for the last 20 years, as a result of structural changes in the economy and increased energy efficiency.

But we are an international outlier. On a per capita basis, the average high-income country has roughly double our electricity consumption, while the United States and South Korea have close to triple.

Last year, however, demand actually went up, for the second year running.<sup>1</sup> And in the coming decades that trickle is likely to become a flood, as data centres are built, air conditioning is fitted and cars, heating and industry all electrify. In 2030 the National Energy System Operator (NESO) expects demand to be 14% higher than in 2024; in 2035 the estimate is 37%; and in 2050 anywhere from 93% to 175%.<sup>2</sup>

**‘ The Government seems intent on planning out in exquisite detail exactly how our energy system should look – and sticking consumers with the bill for all of it ’**

Equally, the grid will soon enough be pretty well decarbonised (though we doubt that will be by 2030). Which means that for the first time in quite a while this country will need new power stations not for the sake of decarbonisation, but because homes and businesses up and down the country will be hungry for the energy.

This raises the tantalising prospect that Britain could become a nation of genuine energy abundance, with the cheapest new sources of generation (whatever they may be) springing up to deliver the power. But if prices remain high, one of two things will happen. Either this great swell of demand will be cut off at the knees, and those data centres and factories and all the rest of it will go elsewhere. Or electrification will still happen, not least by government diktat, but we will all pay far more for it than we should.

The key change we need to deliver that abundant future, we argue, is to let markets take the lead on what gets built – not Whitehall. To move away from our current addiction to subsidies and central planning, and unleash private sector dynamism and competition to source the cheapest power for consumers. To cut back the regulatory cruft that has resulted in more than 10,000 pages of energy industry codes, and a cost to serve a customer account that is around double the level in France.<sup>3</sup>

1 ‘E. Gosden, ‘Demand for electricity in UK surges after two decades of decline’, *The Times*, December 2025. [Link](#)

2 Per FES 2025. Note the 2030 and 2035 figures use the 10 Year Forecast (NESO's best expectation), but the full range is 12%-19% for 2030 and 29%-60% for 2035 (the latter both include the ‘Falling Behind’ scenario where Net Zero is not reached). ‘Future Energy Scenarios: Pathways to Net Zero’, National Energy System Operator, 2025. [Link](#)

3 ‘The future of energy regulation: more efficient, lower cost, better outcomes’, Energy UK, October 2025. [Link](#)



This may seem a far cry from today's world – and yet the seeds of it have already been sown. Renewables, for example, are widely seen as utterly dependent on subsidy. And yet they are getting built without state contracts, all over the country. The largest currently operating solar farm in the UK, the 373 MW Cleve Hill project in Kent, has a private contract from Tesco for two thirds of its output, while the second largest, the 75 MW Llanwern farm in Wales, is entirely private.<sup>4</sup> Similarly there is a strong private market for onshore wind, which is even extending into offshore.<sup>5</sup>

Meanwhile, the advent of Small Modular Reactors (SMRs) heralds a nuclear revolution – one that could and should be driven by the markets, not government. Smaller, more easily scalable and financeable reactors could be used in a variety of settings, from industrial clusters to data centres, and offer critical baseload power. Already in the US, the tech giants are signing deals to snap up nuclear power – and while SMRs will need support in the near term as they scale up, once mature they should be able to break free from the state.

**‘ To deliver an abundant energy future,  
we need to let markets take the lead  
on what gets built – not Whitehall ’**

These Power Purchase Agreements (PPAs) are being driven by businesses seeking to take control of their energy, cut carbon and lock in prices over the longer term. And these contracts have been taking off in recent years – the European PPA market more than doubled between 2020 and 2025, albeit down from a record year in 2023.<sup>6</sup> Britain has the fifth largest market in Europe – impressive, but far behind leaders such as Spain who have pressed ahead with the private model.<sup>7</sup>

In short, the post-decarbonisation era will need a new policy paradigm – one based on abundance, markets and competition. Below we set out the key guiding principles for a market-driven electricity policy:

- (1) The explicit goal should be energy abundance and enduring cheap prices for consumers
- (2) Markets will do a better job of picking the capacity mix than Government – whether renewables, nuclear or new technologies

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4 M. Green, 'UK's largest solar plant Cleve Hill supplying full power to the grid', *Solar Power Portal*, July 2025. [Link](#)  
M. Green, 'Quinbrook secures offtake agreements with Tesco and Shell for 363 MW Cleve Hill Solar Park', *Solar Power Portal*, October 2024. [Link](#). Note that UKIB played a role in the financing for Llanwern deal, albeit with the revenue still secured via a PPA rather than a CfD. 'UK's Largest Operating Solar Farm Secures 20-Year Sleeved PPA', *NextEnergy Capital*, October 2024. [Link](#). 'UK Infrastructure Bank confirms position as cornerstone investor in UK's largest subsidy-free solar power fund', *UK Infrastructure Bank*, August 2022. [Link](#)

5 'Amazon Signs Agreement with ENGIE to Procure 473 MW of Renewable Energy from the Moray West Offshore Wind Farm in Scotland', *ENGIE*, January 2024. [Link](#). A. Buljan, 'Moray West: First UK Round 4 Offshore Wind Project to Reach Financial Close', *OffshoreWind.biz*, April 2023. [Link](#). 'ENGIE and Google Conclude a Corporate PPA Relying on Ocean Winds Offshore Wind Development', *ENGIE*, November 2022. [Link](#)

6 N. Briet, D. Hischier & A. Valassas, 'Renewables Market Outlook 2026', *Pexapark*, 2026. [Link](#). Note that while this report prefers to use Pexapark data as explained below, the relevant 2025 figures are not yet available, and RE-Source at least provides an indication of the overall trend even if the individual transactions have not been screened to the same degree.

7 Note that as explained below, the term PPA can have a variety of meanings. This statistic is from data provider Pexapark, whose primary criterion for inclusion is bearing price risk, and thus excludes e.g. RtM PPAs for CfD assets. That said, it includes PPAs for existing assets with tenors of five years or longer, so the data will not all be new-build assets. N. Briet, D. Hischier & A. Valassas, 'Renewables Market Outlook 2026', *Pexapark*, 2026. [Link](#)



- (3) Subsidies should have sunsets: while novel technologies will require Government support as they scale up, they should not be reliant on this over the longer term
- (4) All technologies should compete on a level playing field, bearing the same set of risks and costs – so that the cheapest ones win out
- (5) For mature technologies, risk should sit in the private sector, not be socialised via consumers
- (6) The domestic retail market should be driven by innovation and competition, not overbearing regulations and price controls
- (7) Further competition in our transmission and distribution networks should be encouraged alongside ever-sharper locational price signals
- (8) Government's primary role should be in ensuring security of supply, not dictating the shape of the market

Get this right, and Britain can become a nation of cheap, abundant power. Get it wrong, and we will be locking in managed decline.

Accordingly, Chapter 1 of this report provides an overview of how we get our power, and discusses why our prices are so expensive. Chapter 2 looks at the Government's energy policies, especially Clean Power 2030 and Great British Energy. Chapter 3 examines the pros and cons of renewables, and asks why they are still so dependent on subsidy. Chapter 4 does the same for nuclear, examining in particular the recent funding package for Sizewell C. Chapter 5 looks at the rise of PPAs, and what we could do to boost their take-up. Chapter 6 looks at other areas where competition could play a greater role, namely gas plants, transmission and distribution, and the domestic retail market. Finally, Chapter 7 fleshes out a longer-term vision of the future – and sets out how we can get back to an energy system guided by markets, not ministers.

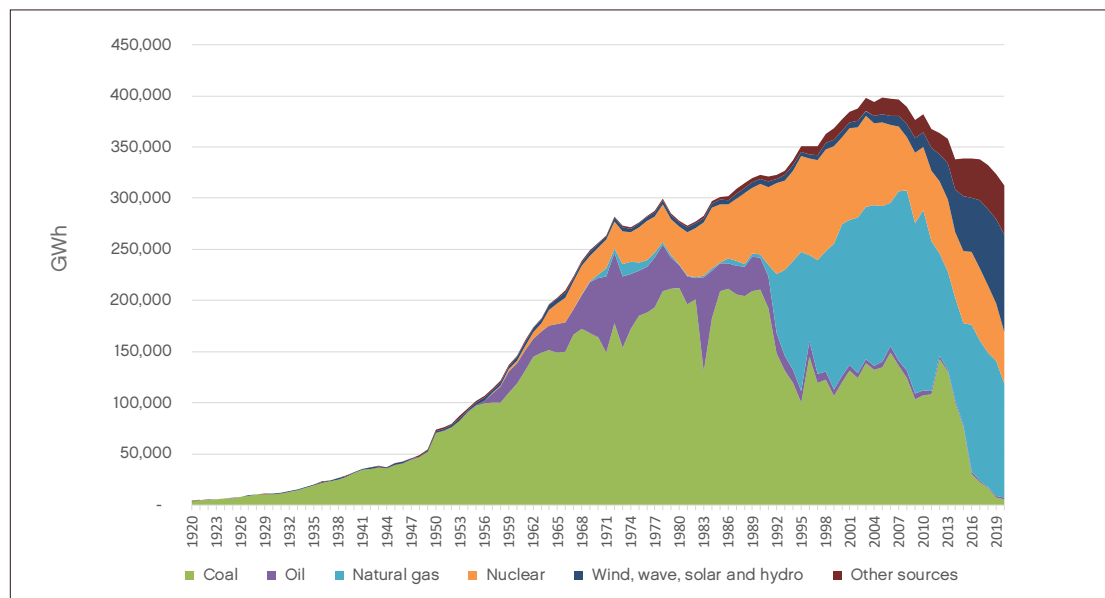


# Chapter 1: How Do we Get our Power?

Understanding power begins with the physics that govern it. Two properties are of outstanding importance. First, electricity cannot be stored in large quantities, and thus supply must match demand every second of every hour of every day. Too much or too little and one risks blackouts. Second, electricity can be transported over great distances with relatively little loss, and thus the power supplying a home or business can be located next door or hundreds of miles away. And because the electricity generated from one technology or individual plant is indistinguishable from the next, price is the principal differentiating factor in the market.<sup>8</sup>

The mix of technologies used to supply our power has changed hugely over the last hundred years, as the chart below illustrates.<sup>9</sup> Coal dominated for much of the last century, displaced temporarily by oil in the 1970s and 1980s, and more permanently by gas generation over the last 30 years. Nuclear generation began in the 1950s and expanded significantly in the 1980s as we built more stations, but has subsequently declined. More recently, renewables have expanded from a small base in the 2000s to represent a significant portion of our energy today. (Note that as Northern Ireland is part of the all-island Irish grid, most facts and figures in this report refer to Great Britain, ie England, Wales and Scotland – though the chart below is for the UK as a whole.)

## UK generation mix from 1920-2020



Source: DESNZ<sup>10</sup>

- 8 The terms electricity and power are used throughout this report. Electricity refers to the flow of electrical energy throughout the system, and power is the measure of how much of it is being transferred or used at a specific time.
- 9 T. McGarry, 'UK electricity capacity and generation by fuel between 1920 and 2020', *Department for Energy Security & Net Zero*, August 2025. [Link](#)
- 10 Energy Trends: June 2023, special feature article – UK Electricity capacity and generation by fuel between 1920 and 2020', *Department for Energy Security & Net Zero*, June 2023. [Link](#)

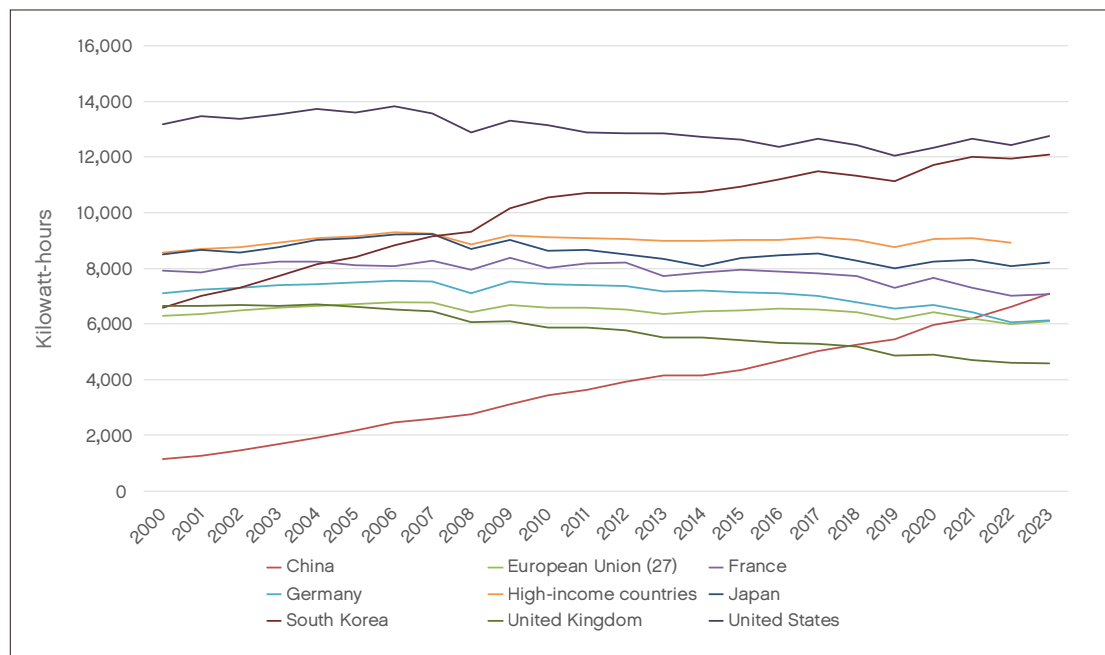


As our generation mix has changed over time, so has the structure and ownership of the stations and network. Whereas the early period was characterised by a somewhat haphazard mix of companies and local authorities, the post-war Labour government nationalised power generation, while the grid was subsequently expanded.<sup>11</sup> Public ownership was later reversed under the Thatcher and Major governments, leading to the structure we have today. Power generators are privately owned (though subsidised to a large degree, as we will see), while homeowners and businesses are free to pick any supplier they wish. Similarly our power grids (national and local) are privately owned, though more heavily regulated given their natural monopoly, while day-to-day operation of the system is in the hands of a publicly owned ‘system operator’.

But how much power do we actually consume? As the graph above shows, total generation (and thus total demand) actually peaked in the 2000s, and has declined since then. In part this decline represents improvements in energy efficiency (and likely a response to higher prices), but also the results of structural changes in the economy (e.g. a shift towards services and higher-value manufacturing).<sup>12</sup> Indeed, while household and commercial consumption are down 16% and 10% respectively since 2000, industrial consumption has decreased by 28% over the same period.<sup>13</sup>

This makes us something of an outlier among our peers, as the below graph shows. While a number of developed nations have experienced declines in per capita demand to some degree, the UK stands out for how low our per capita demand now is. The average for high-income countries is roughly double our levels, while the United States and South Korea have close to triple.

### Per capita electricity demand over time



Annual average electricity demand (i.e. generation adjusted for imports & exports) per person, in kWh

Source: Our World in Data 2026 (with source data from Ember)<sup>14</sup>

11 A. Chalmers, ‘How the World’s First Electric Grid Was Built’, *Works in Progress*, June 2025. [Link](#)

12 ‘Energy Consumption in the UK (ECUK) 2025’, *Department for Energy Security & Net Zero*, December 2025. [Link](#)  
D. Toke, ‘Why has UK electricity consumption kept declining?’, *Energy Revolutions Substack*, August 2024. [Link](#)

13 ‘Digest of UK Energy Statistics (DUKES) 2025: Chapter 5 – Electricity’, *Department for Energy Security & Net Zero*, 2025. (Note: these are UK figures, not GB.) [Link](#)

14 ‘Total Electricity Demand Per Person’, *Our World in Data*, 2026 [Link](#)



The subsequent sections will examine each of the major components of our system – their history, current function, and how we expect them to develop over the next decade or so.

## Gas as the bedrock of today's system

During the 1990s, deregulation and the exploration of the North Sea oil and gas fields saw coal displaced as the UK's primary electricity source. The so-called 'Dash for Gas' resulted in gas growing from just 2% of power generation in 1990 to a third by 2002.<sup>15</sup> Today, the UK operates a fleet of 35 combined cycle gas turbines (CCGTs) left behind from those boom years as well as the more recent 'peaker' plants: turbines that are held on standby to ramp up when there is peak demand or there is an electricity shortfall.<sup>16</sup>

**‘ The so-called ‘Dash for Gas’ resulted in gas growing from just 2% of power generation in 1990 to a third by 2002 ’**

Gas plays a critical back-up role in today's system, filling in the gaps when the output from renewables is low (on cloudy and/or still days). Moreover, as the 'marginal producer' in the energy market, it disproportionately affects wholesale electricity prices: though only supplying 27% of our power last year, gas sets wholesale prices very often (97% of the time in 2021, and perhaps 85% of the time in 2024).<sup>17</sup>

Though gas should continue to shrink as a proportion of overall electricity generation, it is going to remain a feature of the grid mix for a while yet. The Labour Government's Clean Power 2030 plan seeks to limit gas to 5% of generation, with 35 GW of capacity held as a strategic reserve to secure supply<sup>18</sup> – but still envisages gas setting the price between 15% and 47% of the time.<sup>19</sup>

## The rise of renewables

Since 2010, renewable capacity in the UK has grown remarkably, from less than 10% of UK generation to more than 50% in 2024.<sup>20</sup> There have been multiple mechanisms to promote the rollout of renewable capacity. In 2002 the Renewables Obligation required electricity suppliers to source a set amount of electricity from eligible renewable sources.<sup>21</sup> This was later superseded by the Contracts for Difference (CfD)

15 Energy and Climate Change Select Committee, 'The UK's Energy Supply: security or independence?', *UK Parliament*, May 2011. [Link](#)

16 'Managing Decline: A Regulated Asset Base for Legacy Gas in the Age of Clean Power', *Stonehaven*, May 2025. [Link](#)

17 The commonly-cited Zakeri et al. study is the most recent peer-reviewed paper the author is aware of (based on 2021 data), but the ECIU for example uses a rough estimate of 85% for 2024. B. Zakeri et al, 'The role of natural gas in setting electricity prices in Europe', *Energy Reports*, November 2023. [Link](#). Marginal Gains: how wind is pushing gas out of the power market and cutting costs', *Energy & Climate Intelligence Unit*, October 2025. [Link](#). 'Britain's Energy Explained: 2025 Review', *National Energy System Operator*, January 2026. [Link](#)

18 'Managing Decline: A Regulated Asset Base for Legacy Gas in the Age of Clean Power', *Stonehaven*, May 2025. [Link](#)

19 D. Smith, 'The Great Grid Gamble', *Centre for Policy Studies*, November 2024. [Link](#) Page 4

20 'Digest of UK Energy Statistics 2012', *Department of Energy & Climate Change*, July 2012. [Link](#). 'Official stats show renewables generated over half UK's electricity for the first time in 2024', *RenewableUK*, March 2025. [Link](#)

21 '2010 to 2015 government policy: low carbon technologies', *Department of Energy & Climate Change*, May 2015. [Link](#)



scheme, whereby generators are guaranteed a fixed strike price, with contracts allocated according to competitive blind auctions.

Out of the three primary renewable technologies, offshore wind has seen the fastest growth over the last 15 years, with total capacity at 14.7 GW at the close of 2024 and a further 6.3 GW of capacity currently undergoing installation.<sup>22</sup> The introduction of CfDs has proven particularly beneficial for offshore deployment, with the most recent auction round offering strike prices of £95 per MWh (2025 prices).<sup>23</sup> Overall, offshore wind generated 17.2% of the UK's electricity in 2024.<sup>24</sup>

**‘ The introduction of CfDs has proven particularly beneficial for offshore deployment, with the most recent auction round offering strike prices of £95 per MWh (2025 prices). Overall, offshore wind generated 17.2% of the UK's electricity in 2024 ’**

Onshore wind initially benefited from the old Renewables Obligation scheme before a de facto ban in England between 2015 and 2024 slowed the deployment of new installations. At the end of 2024, there was 15.7 GW of installed onshore capacity; CfDs have helped to fund 5.1 GW of that figure. In the most recent auction round, 1.3 GW of onshore wind projects were awarded contracts at strike prices of around £75 per MWh (2025 prices).<sup>25</sup>

Solar in the UK has grown from 0.1 GW of capacity in 2011 to more than 21 GW by the end of 2025.<sup>26</sup> Though domestic rooftop solar makes up the overwhelming majority of solar installations (86%), solar farms and commercial rooftop solar account for 69% of total solar capacity.<sup>27</sup> Initially benefiting from Feed-In Tariffs (FITs) and the Renewables Obligation, CfDs now underpin large-scale solar rollout: 4.9 GW of new capacity received contracts at Allocation Round 7 in 2026.<sup>28</sup> However, solar's contribution to electricity output is low – 5.2% – as a consequence of low annual load factors, or in layman's terms a lack of sunlight.<sup>29</sup>

22 D. Sutherland & M. Bradbury, 'UK wind and global offshore wind: 2024 in review', *Renewable UK – Energy Pulse Blog*, February 2025. [Link](#)

23 Current prices calculated according to most recent Bank of England inflation data. 'Contracts for Difference Allocation Round 7 results', *Department for Energy Security & Net Zero*, February 2026. [Link](#)

24 'Official stats show renewables generated over half UK's electricity for the first time in 2024', *RenewableUK*, March 2025. [Link](#)

25 'UK wind and global offshore wind: 2024 in review', *RenewableUK Energy Pulse Blog*, February 2025. [Link](#) 'Onshore Wind Taskforce strategy', *Department for Energy Security & Net Zero*, July 2025. [Link](#) 'New Auction delivers unprecedented clean, homegrown power', *Department for Energy Security & Net Zero*, February 2026. [Link](#)

26 G. Hughes, 'The Economics of Utility-Scale Solar Generation', *Renewable Energy Foundation*, 2023. [Link](#) 'Solar photovoltaics deployment', *Department for Energy Security & Net Zero*, Jan 2026. [Link](#)

27 K.M. Ross, 'UK solar capacity up 5.9% year-on-year', *Solar Power Portal*, May 2025. [Link](#)

28 'New Auction delivers unprecedented clean, homegrown power', *Department for Energy Security & Net Zero*, February 2026. [Link](#)

29 'Official stats show renewables generated over half UK's electricity for the first time in 2024', *RenewableUK*, March 2025. [Link](#)



## The decline of British nuclear

Though the UK was the first country in the world to introduce civilian nuclear power, its nuclear industry now finds itself in a parlous state: of its current fleet of nine operating reactors, all but one are due to be decommissioned by this decade's end.<sup>30</sup>

The fleet comprises eight Advanced Gas-Cooled Reactors (AGRs), a result of extensive nuclear construction between the late 1970s and late 1980s, with a further Pressurised Water Reactor (PWR) completed at Sizewell B in 1995.<sup>31</sup>

At its peak in the mid-1990s, nuclear power provided more than a quarter (13 GW) of the UK's electricity demand. Today it is only 4 GW – approximately 15% of the electricity mix.<sup>32</sup>

**‘ With UK electricity demand expected to double by 2050, the need to replace the capacity of the nuclear plants that are shutting down has become a pertinent issue ’**

With UK electricity demand expected to double by 2050, the need to replace this loss of zero-carbon baseload capacity has become a pertinent issue. A new plant at Hinkley Point C was approved a decade ago and a sister plant at Sizewell C in Suffolk was approved in 2025 by the Government.

However, Hinkley Point C is now running years behind schedule and has seen its costs swell from £18bn to £48bn.<sup>33</sup> Sizewell C could cost nearly as much, thanks to a bloated regulatory regime that drowns such projects in red tape. Without comprehensive reform, or significant advances in small modular reactor technology, future nuclear construction is likely to remain limited in scope.

## Other key aspects of the power system

### *Biomass*

Today, biomass accounts for 11% of the UK's power generation.<sup>34</sup> Reliant on burning wood pellets to generate electricity, biomass is controversial: it has been the recipient of extensive government subsidy under green schemes, but its carbon credentials have been heavily questioned.<sup>35</sup> Despite this, between 2002 and 2023, biomass facilities received over £16bn in subsidies, and the Government announced this year that Drax – the biggest biomass provider – will continue to generate electricity until at least 2031 under a new CfD scheme that will hand it a further

30 E. Ives, 'Small Wonders: How SMRs can power a clean, competitive and secure economy', *The Entrepreneurs Network*, September 2024. [Link](#)

31 'Nuclear Power in the United Kingdom', *World Nuclear Association*, September 2025. [Link](#). N. Watson, P. Bolton & N. Sutherland, 'Civil Nuclear Roadmap: debate pack', *House of Commons Library*, February 2024. [Link](#)

32 'Interim report', *Nuclear Regulatory Taskforce*, August 2025. [Link](#)

33 S. White, J. Pickard & R. Millard, 'UK nuclear plant hit by new multiyear delay and could cost up to £46bn', *Financial Times*, 2024. [Link](#). E. Gosden, 'EDF secures funding for Hinkley Point C nuclear plant', *The Times*, June 2025. [Link](#)

34 R. Millard, 'UK cannot prove sustainability of biomass power plants, warns watchdog', *Financial Times*, January 2024. [Link](#)

35 'Panorama, The Green Energy Scandal Exposed', *BBC One*, October 2022. [Link](#). P. Stafford, 'FCA opens investigation into Drax annual reports', *Financial Times*, August 2025. [Link](#)



£1.2 million per day.<sup>36</sup> However, under this scheme, Drax will only contribute 1.8% of total energy supply by 2030.<sup>37</sup>

### Batteries

The rollout of renewable capacity in the UK means a large expansion in battery capacity. Currently at 6 GW, grid scale battery storage systems are expected to grow substantially: by 2030, between 23 GW and 27 GW of battery storage will be required to meet the new Government's Clean Power 2030 target. Between April and June 2025, planning applications for 8.4 GW of storage were filed.<sup>38</sup> However, as critics of renewables are quick to point out, these batteries currently store energy for a matter of hours, not days: the total combined capacity of current planning applications for new batteries is 127 GW, of which 98% will be able to discharge power for two hours or more.<sup>39</sup>

### Interconnectors

The UK currently has nine operational electricity interconnectors, representing 9 GW of total capacity, which allow surplus electricity to flow between Britain, France, Belgium, the Netherlands, Denmark, Norway and Ireland.<sup>40</sup> Interconnectors play an important role in smoothing out prices across these markets, allowing the transfer of cheaper power to more expensive markets. More interconnectors are planned, with a further 16 GW of capacity to come online by 2035.<sup>41</sup>

While these links allow the UK to export surplus power, the country is overwhelmingly a net importer of energy: in 2024, net power imports to the UK totalled 33.4 terawatt-hours, or 10.5% of domestic demand.<sup>42</sup>

**‘ In 2024, net power imports to the UK totalled 33.4 terawatt-hours, or 10.5% of domestic demand ’**

## How does the power get to us?

Once power has been generated, it needs to be transported to the homes and businesses that use it – the job of the grid. This is broadly split into two systems – transmission and distribution.

The transmission network is made up of high-voltage cables that transport power over long distances, akin to motorways in a road network. Our transmission system is privately owned by three companies (one which covers England & Wales, and two which cover Scotland), and is subject to price-control regulation from Ofgem given its natural monopoly status.

36 R. Millard, 'UK cannot prove sustainability of biomass power plants, warns watchdog', *Financial Times*, January 2024. [Link](#)

37 F. Mayo, 'UK biomass phase-out is now in sight', *Ember Energy*, April 2025. [Link](#) Page 3

38 C. Murray & R. Millard, 'UK green power surges with record approvals for new renewable energy capacity', *Financial Times*, August 2025. [Link](#)

39 D. Sutherland, 'Battery storage capacity in the UK: the state of the pipeline', *RenewableUK*, December 2024. [Link](#)  
'January 2025: GB battery storage research roundup', *Modo Energy*, January 2025. [Link](#)

40 J. Leake, 'Britain to rely on France to avoid blackouts this winter', *Telegraph*, June 2025. [Link](#). R. Millard & J. Pickard, 'Can Britain's neighbours help it keep the lights on?', *Financial Times*, May 2025. [Link](#)

41 'Interconnectors' role in transitioning to net zero', *National Energy System Operator*, August 2023. [Link](#)

42 Total UK energy demand in 2024 was 319 TWh:  $33.4/319 \times 100 = 10.47\%$ . 'Chapter 5: Electricity', *DUKES 2025*. [Link](#)



However, the transmission grid is in a somewhat difficult position at the moment. We have built out a substantial amount of renewables, without the cables to carry the power to where it is needed. This means that we often have to pay power stations to stop producing electricity, because the system can't handle the load. These so-called 'constraints' are costly for consumers (nearly £2bn in 2024/25) and have increased markedly over the last few years.<sup>43</sup> Britain is therefore undertaking a substantial build-out of new grid capacity, not least in order to meet the stretching demands of Labour's clean power target.<sup>44</sup>

Once the power is transported across the country via the transmission networks, it then needs to reach the homes and businesses that use it – the job of the distribution networks. In the roads analogy, distribution networks are akin to local roads – reaching everywhere, but taking a smaller, slower volume of traffic (or in this case, operating at lower voltages). There are 14 'Distribution Network Operators' (DNOs), each responsible for a distinct geographic area of Great Britain.<sup>45</sup> While privately owned, the DNOs too are subject to strict regulation, though since the early 2000s they have faced competition from 'independent DNOs' for new connections.

Distribution networks are also undergoing substantial expansion and change as a result of decarbonisation. While most large generating plants connect to the transmission network, smaller assets are increasingly connecting to the distribution network instead, particularly solar. On the demand side, households with electric cars (EVs) and heat pumps consume substantially more electricity than their peers, and ditto for businesses switching to electricity from gas or other sources. Both of these trends mean that the distribution networks will need to expand substantially to accommodate the new power that will soon be flowing through their wires.<sup>46</sup>

**Industry faces bills that are 90% higher than the average for major European economies, with household bills 20% higher. This has had a crushing impact**

## How do we buy our power?

The final piece of the jigsaw is the energy suppliers. At the most basic level, they buy power from the generators and then sell it on to households and businesses. Some suppliers own power plants and can supply their customers directly, while others (particularly newer ones) buy all of their power from other generators. Suppliers tend to be the face of the energy industry for the average person, and the Government has tasked them with running a number of schemes such as the smart meter rollout and the Warm Home Discount.<sup>47</sup>

The domestic power market is, again, heavily regulated. Ofgem (often at the behest of the Government) has created an ever-expanding thicket of red tape – the standard conditions of an electricity supplier license are now over 600 pages long.<sup>48</sup>

43 '2025 Annual Balancing Costs Report', *National Energy System Operator*, May 2025. [Link](#) Page 19

44 A.Walker & A. Adcock, 'Delivery of electricity grid upgrades', *House of Commons Library*, November 2024. [Link](#)

45 'RIIO-2 Electricity Distribution Summary Annual Report: 2023-24', *Ofgem*, 2025. [Link](#) Page 4

46 'Ofgem outlines transformational framework for local electricity networks to deliver clean power and support growth', *Ofgem*, April 2025. [Link](#)

47 'Supplier Smart Metering Installation Targets', *Ofgem*, n.d. [Link](#), 'Warm Home Discount: Guidance for Licensed Electricity Suppliers and Licensed Gas Suppliers', *Ofgem*, May 2011. [Link](#)

48 A. Bell, 'The Future of Economic Regulation', *Stonehaven*, August 2025. [Link](#), 'Supplier Smart Metering Installation Targets', *Ofgem*, n.d. [Link](#), 'Warm Home Discount: Guidance for Licensed Electricity Suppliers and Licensed Gas Suppliers', *Ofgem*, May 2011. [Link](#)



Meanwhile the once-temporary domestic price cap has now become a permanent feature of the market.

The business energy market is subject to less onerous regulation (for example the price cap only applies in the domestic market). And compared to the relative homogeneity of the domestic market, businesses have a wide variety of consumption levels and needs. Larger businesses in particular tend to be more sophisticated buyers of power, and some contract with generators directly, as discussed below. However, despite their sophistication (and Government exemptions for the most energy-intensive companies), firms have been hit by high prices just as households have, resulting in many energy-intensive firms shutting down.

**‘ Even as the immediate crisis receded, bills remain elevated, with the average dual-fuel household on the price cap paying £1,758 as of January, compared to £1,100 pre-crisis ’**

## So why are power prices so expensive?

Anyone following the power sector over the last few years has been treated to a rather depressing spectacle. Russia’s invasion of Ukraine saw bills skyrocket, forcing the Government to intervene to subsidise households and businesses, costing an estimated £44bn.<sup>49</sup> Even though the immediate crisis has receded, bills remain elevated, with the average dual-fuel household on the price cap paying £1,758 as of January 2026, compared to ~£1,100 pre-crisis.<sup>50</sup>

Meanwhile, industry faces bills that are 90% higher than the average for major European economies, with household bills 20% higher.<sup>51</sup>

Needless to say, this has had a crushing impact on households and businesses alike, dampening economic growth and serving as a deterrent to any investor wondering about setting up an energy-intensive business in the UK.

So why are our prices so expensive? The debate over the answer to this question has raged over the last year or so and has become almost tribal at this point. For one side, the answer is obviously gas prices. For the other, the answer is obviously renewables.

The raw data below shows the breakdown of a domestic electricity bill over the last few years, alongside 2017 for comparison, and increases in absolute and percentage terms on the right (in nominal figures, so unadjusted for inflation).<sup>52</sup> Looking at the spike in bills over the last five years, wholesale costs (driven by gas prices) have increased far more than any other component, including renewable subsidies. However, over a longer horizon, subsidies, networks and other costs all substantially contributed to the increase.

49 ‘Energy Bills Support: an update’, *National Audit Office*, November 2024. [Link](#)

50 ‘The History of Ofgem’s Price Cap’, *Electricity Prices*, 2026. [Link](#). Note that in 2023, Ofgem adjusted the methodology for calculating average household consumption, making direct comparisons with pre-crisis values difficult. Nonetheless, adjusted for inflation, £1,100 would equate to £1,379 as of December 2025 (the most recent Bank of England inflation data available). ‘Decision on revised Typical Domestic Consumption Values for gas and electricity and Economy 7 consumption split’, *Ofgem*, May 2023. [Link](#)

51 ‘Is Britain’s net-zero push to blame for its high energy prices?’, *Economist*, July 2025. [Link](#)

52 Based on 3,100 kWh total consumption. B. James, ‘Electricity Bill Breakdown’, *Electricity Bills 2025*. [Link](#)



## Average annual household electricity bill (nominal)

Family	Sub-component	FY 17-18	FY 19-20	FY 20-21	FY 21-22	FY 22-23	FY 23-24	FY 24-25	25 FYTD (to Dec)	Increase: FY20-21 to 25-26		Increase: FY17-18 to 25-26	
Wholesale	Wholesale	£167	£213	£170	£220	£838	£584	£311	£324	£154	43%	£157	35%
Network	Network	£130	£136	£138	£149	£201	£203	£209	£207	£69	19%	£77	17%
Generation subsidies	Renewables Obligation	£59	£74	£74	£82	£86	£85	£99	£102	£45	13%	£101	22%
	Feed in Tariffs	£14	£17	£19	£21	£14	£21	£23	£23				
	Contracts for Difference	£8	£20	£31	£31	-£22	-£3	£34	£33				
	Capacity Market	£3	£15	£18	£15	£10	£18	£21	£28				
Misc	Supplier costs & margin	£85	£89	£90	£91	£77	£107	£110	£133	£71	20%	£98	22%
	ECO	£9	£11	£14	£16	£16	£22	£27	£27				
	Warm Home Discount	£7	£7	£7	£10	£10	£10	£11	£15				
	Other	£1	£15	£18	£18	£17	£18	£19	£24				
VAT	VAT @ 5%	£24	£30	£29	£33	£62	£53	£43	£46	£17	5%	£22	5%
	<b>TOTAL</b>	<b>£508</b>	<b>£627</b>	<b>£607</b>	<b>£685</b>	<b>£1,309</b>	<b>£1,118</b>	<b>£907</b>	<b>£963</b>	<b>£357</b>	<b>100%</b>	<b>£456</b>	<b>100%</b>

Source: Electricity Bills<sup>53</sup>

To expand on the above: as Ed Miliband would surely tell you, our dependency on gas-fired power undoubtedly has played a star role in raising bills in recent years. The Dash for Gas in the 1990s seemed to herald a new era of cheap gas power, enabled by the North Sea. Yet that dependency backfired spectacularly after Putin's invasion of Ukraine.

While the immediate crisis has subsided, gas prices are still high, sitting at an average of 74p/therm in 2025, relative to annual averages of 61p in 2018, 31p in 2019 and 56p in 2020.<sup>54</sup> And in the UK, gas set the price of power 97% of the time (in 2021, the latest year for which comparable figures are available), compared to 7% in France (with its abundant nuclear) or 24% in Germany (with its mix of coal, hydroelectric and imports).<sup>55</sup>

53 Ibid.

54 'ICE UK Natural Gas Continuous Contract', *Market Watch*, 2025. [Link](#)

55 Figures for 2021, based on academic research. For many European countries 2022 saw gas setting a higher percentage of prices, as detailed in the Draghi report, though GB is not included in those figures. As noted above the ECIU for example uses a rough estimate of 85% for 2024 in GB. B. Zakeri et al, 'The role of natural gas in setting electricity prices in Europe', *Energy Reports*, November 2023. [Link](#). Marginal Gains: how wind is pushing gas out of the power market and cutting costs', *Energy & Climate Intelligence Unit*, October 2025. [Link](#)



Indeed, part of the issue is that coal has been squeezed out of the system. This was undoubtedly good for the planet, but has handed gas power stations market power.<sup>56</sup> And they exploit it to full effect – witness two gas power stations being paid more than £6m each (more than 50 times the market price earlier in the week) to supply just three hours of electricity on a cold, still day in January 2025.<sup>57</sup>

This is not to say that gas will always be so expensive – most experts expect prices to decline substantially through this decade as more LNG supply comes online.<sup>58</sup> But volatility is undoubtedly a feature of international fossil fuel markets, and in the high-price environment of recent years we have been more exposed than most of our peers.<sup>59</sup>

However, it is also worth noting that the Government directly imposes extra costs on gas generators in the form of our carbon price (the UK ETS and the separate Carbon Price Support top-up). Our ETS price has generally traded in the £35-£55/tonne range over the last two years, though there was a significant spike from late 2021 to early 2023 (as high as £98/tonne) and it's currently at £65 as of early February.<sup>60</sup> This is still substantially higher than a decade ago, when carbon under the European scheme we were then part of generally traded under at €10/tonne.<sup>61</sup> The Government has also confirmed that it will rejoin the European carbon trading scheme, which has generally had higher prices from our own, while there is also the Carbon Price Support, a tax on fossil fuels which has remained at £18/tonne since 2016.<sup>62</sup>

**‘ While the offshore contracts that won in 2022 are still cheaper than average wholesale prices this year (£53/MWh vs £81), the most recent contracts are more expensive, at £89-£91/MWh ’**

In other words, while it's difficult to portray carbon pricing as the cause of today's high prices relative to five years ago, over the longer term it has absolutely had an impact. But the real cost, in policy terms, has come from the rollout of renewables.

Indeed, looking back over the last decade, generation subsidies have increased our bills by almost as much as wholesale costs. We are still paying off the legacy contracts from the first generation of subsidies (the Renewables Obligation and Feed-In Tariffs), the cost of which will only begin to reduce in the early 2030s.<sup>63</sup> (The former still makes up 11% of a domestic bill, even though it closed to new entrants in 2017.)<sup>64</sup>

The more recent Contracts for Difference saw a steady decline in prices for offshore wind up to 2022 – before increasing again in the last few years. As a

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56 A. Bell, 'Ending Market Power in the Power Market', *The Unbalancing Mechanism*, November 2024. [Link](#)

57 J. Ambrose, 'Two power station owners to get more than £12m for three hours of electricity', *The Guardian*, January 2025. Note: this occurred within the Balancing Mechanism and not the wholesale market. [Link](#)

58 J. Leake, 'Britain risks missing out on gas price lifeline', *Telegraph*, January 2026. [Link](#)

59 'The impact of higher energy costs on UK businesses: 2021 to 2024', *Office for National Statistics*, May 2025. [Link](#)

60 'European electricity prices and costs', *Ember Energy*, 2025. [Link](#)

61 'EU Carbon Trading Permits', *Trading Economics*, 2025. [Link](#)

62 'Accredited official statistics Environmental Taxes Bulletin historical rates', *HM Revenue & Customs*, June 2025. [Link](#)

63 'Non-commodity costs forecast', *SSE Energy Solutions*, April 2025. [Link](#)

64 B. James, 'Electricity Bill Breakdown', *Electricity Bills*, n.d. [Link](#)



result, while the offshore contracts that won in 2022 are still cheaper than average wholesale prices this year (£53/MWh vs £81), the most recent contracts are more expensive, at £95/MWh.<sup>65</sup> (That said, as a recent ECIU report points out, the addition of renewables has had the effect of cutting wholesale prices themselves.)<sup>66</sup>

As outlined in later chapters, while the addition of zero marginal cost generation is expected to drive wholesale prices lower, renewables also require substantial grid build to accommodate them, as well as backup for when the weather doesn't cooperate. And because of the decision to fund subsidy schemes via bills rather than taxation, more and more programmes will get tacked onto bills in the next few years – hydrogen, CCUS, the new nuclear power stations at Hinkley and Sizewell, to name a few.<sup>67</sup>

**‘Over the last decade, subsidies for renewable generation have increased our bills by almost as much as wholesale costs’**

In short, Britain has a complicated, messy and expensive power system, in which the high price of energy inputs has worked hand-in-glove with heavy government subsidy to push up bills. And under the new Government, things are set to get much worse.

65 R. Millard, Record UK offshore wind auction boosts plan to decarbonise by 2030', *Financial Times*, January 2026. [Link](#)

66 'Marginal Gains: how wind is pushing gas out of the power market and cutting costs', *Energy & Climate Intelligence Unit*, October 2025. [Link](#)

67 'Energy Security Bill Policy Statement – Carbon Dioxide (CO2) Transport and Storage, Hydrogen and Industrial Carbon Capture Business Model support', *Department for Business, Energy & Industrial Strategy (BEIS)*, August 2022. [Link](#). Committee of Public Accounts, 'Carbon Capture, Usage and Storage', *UK Parliament*, February 2025. [Link](#)



# Chapter 2: The State vs the Market

For a Government that talks about pragmatism and practicality, energy is one of the main areas where Labour has explicitly chosen the ideological route, in the form of two flagship policies – Clean Power 2030 and Great British Energy. This chapter will explore whether these are the right solution to Britain’s energy crisis, and what a better answer might look like.

## Clean Power 2030

Decarbonising the grid by 2030 (five years ahead of the Conservative target) was one of Labour’s signature election pledges, and one of the Government’s five ‘missions’ for power.<sup>68</sup> And this is a mission that, despite the ever-growing chorus of doubters (the Centre for Policy Studies included), the Government still seems to have genuine faith in.

Writing in the *Express*, Ed Miliband described clean power as the ‘beating heart of our plan to bring down bills once and for all’, writing that: ‘At the heart of this drive for clean power is our belief that the British people can never again be left exposed to the rollercoaster of global gas markets over which we have no control.’<sup>69</sup>

‘ The report Miliband relied on to substantiate his promise to save households £300 actually said that only £44 would be delivered by following his plan ’

On its face, this might seem like a sensible argument. After all, our energy bills were brought to ruinous heights by our exposure to international gas markets following Putin’s invasion of Ukraine. Surely the quicker we get off gas, the better for our energy security and ultimately household bills? All while making Britain an international leader in the climate space, and our carbon budgets easier to hit.

Unfortunately, this story has a number of very large holes.

First, the notion that sprinting to 2030 would save households a bundle of money was always rather dubious, and looks even more so now. The (in)famous figure of £300 off energy bills (including heating) that Labour loudly trumpeted during the election was based on misleading analysis – as the CPS pointed out at the time. In particular, it used power prices that were still coming down from post-Ukraine highs as a comparison point and overstated the actual savings delivered by dashing to

68 ‘Mission-driven Government’, *Labour Party UK*, 2024. [Link](#)

69 E. Miliband ‘Labour’s plan will cut energy bills once and for all – we’ll take back control’, *Express*, May 2025. [Link](#)



2030. The original report said that only £44 of the £300 saving would be delivered by Miliband's plan, rather than the counterfactual where substantially less progress on renewables was made.<sup>70</sup>

Upon entering office, Miliband commissioned the National Energy System Operator (NESO—the body which runs the grid) to flesh out the 2030 plans.<sup>71</sup> The resulting report found not that his plans would save money but merely that the 2030 sprint would not push up bills.

And yet as CPS analysis showed, even this claim rested on a number of dubious assumptions.<sup>72</sup> Foremost among these were assumptions for gas and carbon prices that were substantially higher than those produced by Miliband's own department, or by independent analysts. The comparisons were also made against an improbable 'strawman' counterfactual, rather than the previous Government's trajectory.

In short, despite repeated claims to the contrary, none of the analysis on which the 2030 plans are based shows they will save households substantial amounts of money on their energy bills, or indeed any money at all.<sup>73</sup> More recent analysis shows bills going in the opposite direction – Rachel Fletcher of Octopus Energy recently told a select committee of MPs that 'if we continue on the path that we're on right now, in all likelihood, electricity prices for a typical customer are going to be 20% higher in four or five years' time than they are now.'<sup>74</sup>

**Despite repeated claims to the contrary, none of the analysis on which the 2030 plans are based shows they will save households substantial amounts, or indeed any money at all**

The second flaw in the plan is in its feasibility. Put simply, many observers believe that achieving the 2030 goal is impossible. Miliband himself has described it as a 'sprint', while Chris Stark (responsible for delivering 2030 inside Government) has declared it 'at the fringes of what's possible'.<sup>75</sup> The NESO report itself says that 'several elements' of the plan involve delivering 'at the limit of what is feasible'.<sup>76</sup>

Indeed, the specifics are daunting – building twice as much transmission network capacity in the next five years as over the last decade, with zero delays, and increasing demand flexibility by 4-5 times from today's levels. This despite Labour giving itself a helping hand by defining 'clean' as 95% decarbonised, rather than say

70 R. Colvile, 'Labour's fantastical sums on energy bills are just hot garbage', *The Times*, June 2024. [Link](#)

71 E. Miliband, 'Advice on decarbonising the power sector by 2030: NESO commission', *Department for Energy Security & Net Zero*, August 2024. [Link](#)

72 D. Smith, 'The Great Grid Gamble', *Centre for Policy Studies*, November 2024. [Link](#)

73 E. Miliband, 'A rebuke to those who said clean power by 2030 was unachievable: they were wrong, we were right', *The Guardian*, November 2024. [Link](#). E. Miliband, 'Labour's plan will cut energy bills once and for all – we'll take back control', *Express*, May 2025. [Link](#)

74 'Green levies to blame for rising energy bills, say suppliers', *Telegraph*, October 2025. [Link](#)

75 'Ed Miliband pledges 'most ambitious reforms to UK energy system in generations'', *The Guardian*, December 2024. [Link](#). A. Blackburne, 'UK to release 2030 clean power action plan by end-2024: Mission Control', *S&P Global*, September 2024. [Link](#)

76 'Clean Power 2030 Implementation Plan', *National Energy System Operator*, November 2024. [Link](#)



98% or 100%. (Admittedly, 95% by 2030 was a Johnson-era target, though this was not repeated by Rishi Sunak – and looked unlikely to be met in any event.)<sup>77</sup>

In short, even if the numbers stacked up (which they don't), actually delivering the 2030 plan is extremely stretching.

This leads on to the third flaw – the risk that blindly sprinting to 2030 ends up making things worse, not better.

With rather bad timing, we are currently attempting to build record amounts of new renewable capacity at a time of high interest rates and tight supply chains – bad conditions for cheap power plants. Yet by tying itself so publicly to the 2030 target, Labour has no choice but to press on regardless, whatever the price.<sup>78</sup>

**‘ We are currently attempting to build record amounts of new renewable capacity at a time of high interest rates and tight supply chains – bad conditions for cheap power plants ’**

The results of the latest offshore wind auction round (AR7) point to exactly this tension. While the auction secured a huge 8 GW of new capacity, strike prices were 10% higher than the previous round (AR6), which in turn was higher than AR3 and AR4 (AR5 saw no bids).<sup>79</sup> And this was despite the Government changing the structure of the auction in several ways to try to engineer lower prices, such as extending the contract duration from 15 to 20 years.

What's more, the final auction budget was nearly double the initial estimate – suggesting that the Government deliberately decided to procure enough capacity to hit the 2030 target, with the full knowledge that this would likely mean higher strike prices.

Now, the extent to which this will raise consumers' bills is disputed, not least because it depends on the future evolution of gas prices and wholesale prices, which will be made lower by this auction, as well as wider costs such as grid reinforcement (and the counterfactual used). But whereas in the autumn there had been rumours that the Government might be preparing to quietly abandon CP30 so as not to raise bills, no such humility was on display in this auction.<sup>80</sup>

The same is true when it comes to grid connections. This is a notoriously troubled area, with new projects waiting up to 15 years to connect, and the queue growing tenfold over the last five years.<sup>81</sup>

77 'British Energy Security Strategy', *Department for Energy Security & Net Zero*, April 2022. [Link](#). 'Powering Up Britain: Energy Security Plan', *Department for Energy Security & Net Zero*, April 2023. [Link](#)

78 'Further reforms to the Contracts for Difference scheme for Allocation Round 7', *Department for Energy Security & Net Zero*, February 2025. [Link](#)

79 R. Millard, 'Record UK offshore wind auction boosts plan to decarbonise by 2030', *Financial Times*, January 2026. [Link](#)

80 K. Stacey & H. Horton, 'Keir Starmer prepares to miss key green target in effort to keep energy bills down', *The Guardian*, October 2025. [Link](#)

81 'Clean energy projects prioritised for grid connections', *Department for Energy Security & Net Zero*, April 2025. [Link](#)



The previous Government set out a series of reforms focused on reducing delays and better managing the queue, which most in the energy world agreed would substantially improve the situation.<sup>82</sup> But the demands of the 2030 sprint – and a natural inclination towards top-down state direction – led the new Government to go further, demanding Ofgem prioritise those projects which are critical to delivering 2030, while putting everyone else at the back of the queue.<sup>83</sup> In other words, if you don't fit within the Government's plans, you may as well take your money elsewhere.

While necessary to deliver 2030, this rips up the previous first-come-first-served process: instead, the state is literally picking winners.<sup>84</sup> Of course, for a Labour Government keen for the state to do more this may be an end in itself – but it's a striking example of the contortions necessitated by the arbitrary 2030 target.

**‘ If the 2030 sprint ends up driving up bills,  
and the Government is widely seen to have  
made a mess of the situation, then it will  
make wider decarbonisation harder ’**

Indeed, the fact that the 2030 target is so arbitrary is perhaps its most fundamental flaw. There seems to be little logic behind it as the date to decarbonise the system, beyond the fact of it being a round number that is five years ahead of the previous Conservative target (which was endorsed by the Climate Change Committee and commonly agreed by G7 nations).<sup>85</sup>

It is important to reiterate that cleaning up our power grid is a good thing, especially if it can be done while keeping energy prices the same or even cutting them. But decarbonisation is not monolithic – there are good, sensible, pragmatic ways to go about it (which the previous Government at least aspired to), and then there is the reckless, zealous 2030 plan.

Indeed, if the 2030 sprint ends up driving up bills rather than reducing them, and the Government is widely seen to have made a mess of the situation, then it will make wider decarbonisation harder. Not only by pushing the running costs of EVs and heat pumps higher, disincentivising people to make the switch, but by discrediting Net Zero as a whole in the eyes of voters and proving the sceptics right that it will only mean higher costs and more disruption to their lives.

82 'Connections action plan: speeding up connections to the electricity network across Great Britain', *Department for Energy Security & Net Zero and Ofgem*, November 2023. [Link](#)

83 'Clean energy projects prioritised for grid connections', *Department for Energy Security & Net Zero*, April 2025. [Link](#). Ofgem, 'Decision on Connections Reform Package (TMO4+)', *Ofgem*, April 2025. [Link](#)

84 'Clean Power 2030 Action Plan', *Department for Energy Security & Net Zero*, December 2024. [Link](#) page 66 'UK grid connections reform: 132 GW renewables to connect by 2030', *Solar Power Portal*, December 2025. [Link](#)

85 'Delivering a reliable decarbonised power system', *Climate Change Committee*, March 2023. [Link](#) 'Carbis Bay G7 Summit Communique', *Prime Minister's Office 10 Downing Street*, July 2021. [Link](#)



## Great British Energy

Alongside Clean Power 2030, the other pillar of Labour's energy policy is Great British Energy (GBE). The Government's ambition is to create a publicly owned energy utility 'to invest in homegrown clean energy' and provide 'real energy independence from foreign dictators' – but in reality it feels like a solution chasing a problem.<sup>86</sup>

First announced while in Opposition, as part of its Green Prosperity Plan, Labour intended Great British Energy to be one of the cornerstones of Rachel Reeves' new 'securonomics' paradigm. Joe Biden's Inflation Reduction Act had recently been signed into law, and a muscular industrial strategy seemed globally fashionable. Indeed, Ed Miliband lavished praise on the Biden plan, calling it 'modern green industrial policy at work' and arguing that the UK 'should match the ambition'.<sup>87</sup>

**‘ Labour pledged to spend £28bn per year on its green ambitions, to be provided by a newly established National Wealth Fund ’**

Labour pledged to spend £28bn per year on its green ambitions, to be provided by a newly established National Wealth Fund. This included funding for Great British Energy, carbon capture and storage (CCUS), home insulation and green steel production.<sup>88</sup> Only £8bn in seed funding was earmarked for GBE itself, though much of the total figure was yet to be allocated (and was famously cut ahead of the election).<sup>89</sup> Of this £8bn, £3bn was carved out for Labour's Local Power Plan, a financing programme for local authorities and community energy groups to support small and medium-scale renewable projects.

Great British Energy was envisioned by Labour as a British rival to state-owned European companies such as EDF and Vattenfall. As Miliband has said, 'every real leader in zero-carbon power has a national champion' – adding that '45% of offshore wind assets are owned by foreign governments'.<sup>90</sup> As Keir Starmer put it in his announcement in 2022, energy bills here 'are paying for schools and hospitals in Stockholm'.<sup>91</sup>

Even when Labour retreated from its wider green ambitions, because it could not afford them, the subsidy for Great British Energy remained.

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86 A. Sparrow, 'Labour formally drops £28bn green pledge and blames Tories for "crashing the economy" – as it happened', *The Guardian*, February 2024. [Link](#)

87 E. Miliband, 'Consistent and clear climate leadership – Miliband's speech to the Green Alliance', *LabourList*, March 2023. [Link](#)

88 K. Starmer, 'British power to the British people – Labour's 2022 conference speech', *LabourList*, September 2022. [Link](#). R. Reeves, 'Biggest overhaul of business taxation in a generation – Labour Party Conference speech', *LabourList*, September 2021. [Link](#)

89 J. Elgot & A. Lawson, 'Great British Energy: What is it, what would it do and how would it be funded?', *The Guardian*, September 2022. [Link](#). J. Pickard, 'Keir Starmer slashes £28bn green spending pledge to £4.7bn in major u-turn', *Financial Times*, June 2025. [Link](#)

90 E. Miliband, 'Consistent and clear climate leadership – Miliband's speech to the Green Alliance', *LabourList*, March 2023. [Link](#)

91 K. Starmer, 'British power to the British people – Labour's 2022 conference speech', *LabourList*, September 2022. [Link](#)



As with Clean Power 2030, GBE has superficial appeal – if the Europeans do it, why shouldn't we? Not to mention that it polls quite well, with 62% of the public backing the idea in principle at the time of Labour's election in July 2024.<sup>92</sup>

Yet as with Clean Power 2030, once you look more closely, the case begins to crumble.

EDF, Vattenfall and Orsted are former state electricity (or oil) monopolies that now operate within competitive energy markets. But GBE must start from scratch. That £8bn certainly may sound like a significant sum to dedicate to this. But does it match the Government's original ambition? Not even close.

**‘ Great British Energy's brief was startlingly thin to begin with. The relevant Act is a mere five pages, of which the company's objectives take up little more than half a sheet ’**

Labour has explicitly stated that GBE is ultimately to become a producer, distributor and retailer of clean energy, akin to EDF. Yet modelling by the Trades Union Congress found that between £61bn and £82bn of public investment will be required by 2035 for GBE to begin to match the scale of EDF, of which £40bn would be frontloaded during the current parliament.<sup>93</sup>

If that is the level of investment required, its current capitalisation is simply inadequate to turn GBE into a major contributor to the UK's energy system. Indeed, in the recent Spending Review, its budget was cut by a further £2.5bn to pay for the SMR programme.<sup>94</sup>

Given this much more limited allocation of capital, GBE seems destined to play a far smaller role in the market. But what is that role, exactly? The details still remain somewhat hazy.<sup>95</sup>

GBE's brief was startlingly thin to begin with. The Great British Energy Act is a mere five pages, of which the company's objectives take up little more than half a sheet. These are:

- The production, distribution, storage and supply of clean energy
- The reduction of greenhouse gas emissions from energy produced from fossil fuels
- Improvements in energy efficiency
- Measures for ensuring the security of the supply of energy (including through projects involving or benefiting local communities)<sup>96</sup>

92 D. Difford, 'How Do Britons Feel about Expanding Renewable Energy?', *YouGov*, August 2024. [Link](#)

93 A. Markova & M. Minio-Paluello, 'Public Power: turning it into reality', *Trades Union Congress*, August 2023. [Link](#)

94 J. Ambrose & R. Partington, 'Great British Energy's promised £8.3bn budget raided to pay for small nuclear reactors', *The Guardian*, June 2025. [Link](#)

95 M. Oliver & J. Leake, 'Ed Miliband's £8bn energy company is sliding into irrelevance', *Telegraph*, June 2025. [Link](#)

96 House of Lords, 'Great British Energy Bill [HL Bill 43] 2024–25', *UK Parliament*, 2024. [Link](#)



A press release in March 2024 outlined GBE's goal to establish itself as an 'expert developer' which will 'develop, invest in, build and operate clean energy projects across the UK... allowing it to grow into our national energy champion'.<sup>97</sup>

What will this portfolio look like? According to its recently published Strategic Plan, the choice seems to be a case of 'all of the above'. In an effort to hedge its bets, GBE wants the portfolio to be 'carefully structured to balance risk', combining 'higher risk, high-growth projects with more stable, lower risk investments to ensure both resilience and sustainable returns'.<sup>98</sup> Thus the company is aiming to build up a portfolio of mature technologies such as solar, onshore wind and storage to help fund more nascent ones – despite acknowledging that many of the former projects would have happened without GBE's money.

**‘ The desire for public ownership of mature technologies seems more driven by ideology than any real need within the energy sector ’**

And therein lies the crux of the matter: GBE still appears to be a solution chasing a problem. While investing in and subsidising nascent technologies is a legitimate role the Government can play, the state already does this in spades. The National Wealth Fund (formerly the UK Infrastructure Bank) invests in green energy projects through equity and debt financing, in addition to low-cost financing for local infrastructure projects.<sup>99</sup>

Regarding investment in supply chains (seemingly a large priority for GBE), other potential sources of funding for offshore wind alone include NWF, the Department for Energy Security and Net Zero, The Scottish National Investment Bank, The Crown Estate, Crown Estate Scotland and The Development Bank of Wales. The latter four bodies put out a joint statement in June 2025 agreeing to 'develop a unified, integrated public finance ecosystem' – seemingly aiming to avoid crossed wires and too many cooks.<sup>100</sup> This would suggest too many public bodies in this space, rather than a crying need for another.

Meanwhile, the desire for public ownership of mature technologies seems more driven by ideology than any real need within the energy sector. Indeed, given that mature renewables already have a wealth of investors and developers, it's difficult to see how GBE's involvement would be truly 'additional', beyond simply increasing the level of public ownership.

GBE instead looks to be all things to please all the right people. It panders to environmentalists, trade unions and local communities – but with enough commercial language to attract the private investors it needs to realise its ambitions. And the early signs are that it is finding it impossible to square this circle. For example, its first investment – in March 2025 – was to chip in with other parts of government to provide £200 million in grants for rooftop solar panels for schools, hospitals and community projects, with no return to the company.<sup>101</sup>

97 'Great British Energy: Developer role and partnership with the National Wealth Fund', *Department for Energy Security & Net Zero*, March 2024. [Link](#)

98 'Strategic Plan', *Great British Energy*, December 2025. [Link](#)

99 S. Chivikula, 'National Wealth Fund', *Institute for Government*, February 2025. [Link](#)

100 'United towards clean power', *Great British Energy*, June 2025. [Link](#)

101 R. Millard, 'Great British Energy's first deal is £110mn grant for NHS and school solar panels', *Financial Times*, March 2025. [Link](#)



This was followed up by £300 million for offshore wind supply chains in April, and then an extra £700m for supply chains in June's Industrial Strategy, now rebranded as the 'Energy, Engineered in the UK' programme.<sup>102</sup> This funding is expected to be 'deployed predominantly as targeted grants to support and unlock UK supply chain projects' – not quite the public ownership promised, nor the commercial basis of operations.<sup>103</sup>

Not only are these grants not actually being made in the expectation of a return, none actually require a new public body to achieve them. And if the intention really is to own and operate generating infrastructure, the ever-dwindling pot of funding looks pitiful relative to what would be required to recreate Orsted or EDF – particularly on a timescale that would be relevant for the 2030 ambition.

**‘ Not only are many of Great British Energy's grants not actually being made in the expectation of a return, none actually require a new public body to achieve them ’**

## The Chancellor's recent interventions

In the recent Budget, the Government made several interventions on energy bills, touting a headline saving of £134 per year based on the Q1 2026 price cap for a dual fuel household.<sup>104</sup> This combined two measures – the first of which was scrapping the ailing Energy Company Obligation (ECO) scheme, saving £60.

The ECO scheme was designed to tackle fuel poverty by funding energy efficiency measures like home insulation. But a recent National Audit Office report concluded that 'clear failures in the design and set-up' had led to 'widespread issues with the quality of installations and suspected fraud'.<sup>105</sup> The measure will save £1.7bn per year, though the Government has now allocated further funding to fuel poverty in the Warm Homes Plan.<sup>106</sup>

The second measure is funding 75% of the cost of the Renewables Obligation for households (the legacy scheme which subsidised the roll-out of renewables before the introduction of the CfD) out of taxation rather than energy bills for the next three years. This will take £67 off bills. However, this is not a case of eliminating the cost – it's levying the same amount, just via taxation rather than energy bills.

Moreover, neither measure helps businesses struggling with their energy bills. ECO is only levied on households in the first place, while the Government has chosen to only

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<sup>102</sup> 'Prime Minister launches major boost for UK clean energy industry', *Prime Minister's Office 10 Downing Street*, March 2024. [Link](#). 'Strategic Plan', *Great British Energy*, December 2025. [Link](#). 'Powering Britain's future', *Department for Energy Security & Net Zero*, July 2024. [Link](#)

<sup>103</sup> 'United towards clean power', *Great British Energy*, June 2025. [Link](#)

<sup>104</sup> 'Budget 2025: Strong Foundations, Secure Future [HC1492]', *HM Treasury*, November 2025. [Link](#)

<sup>105</sup> 'Energy efficiency installations under the Energy Company Obligation', *National Audit Office*, October 2025. [Link](#)

<sup>106</sup> R. Reeves, 'Autumn 2025 Budget Speech', *UK Parliament*, November 2025. [Link](#). 'Budget 2025: Strong Foundations, Secure Future [HC1492]', *HM Treasury*, November 2025. [Link](#). D. Dunne, J. Gabbatiss & M. Lempriere. 'Q&A: What UK's 'warm homes plan' means for climate change and energy bills', *Carbon Brief*, January 2026. [Link](#)



subsidise Renewables Obligation costs for households.<sup>107</sup> Claire Coutinho, Miliband's Tory shadow, recently called on the Government to go further and scrap the scheme entirely via primary legislation, benefiting households and businesses alike. (Though accomplishing this in a way that doesn't dent investor confidence could be a difficult needle to thread.)<sup>108</sup>

And while both of the measures announced by the Chancellor are ultimately welcome, neither of them deals with the underlying issues causing energy bills to be high in the first place.

**‘ The unifying theme of both Clean Power 2030 and Great British Energy is the role of central planning. The former requires a dramatic expansion of the state’s role, which the latter helps to facilitate ’**

## Sleepwalking into a centrally planned power market

The unifying theme of both Clean Power 2030 and Great British Energy is the role of central planning. The former requires a dramatic expansion of the state's role, which the latter (incrementally) helps to facilitate. Yet we would argue that the ever-expanding role of the state is itself the key demon to be slayed if we are serious about cheaper power.

Nigel Lawson famously set out the free-market vision for energy policy in 1982: ‘I do not see the government's task as being to try and plan the future shape of energy production and consumption. It is not even primarily to try to balance UK demand and supply for energy. Our task is rather to set a framework which will ensure that the market operates in the energy sector with a minimum of distortion and energy is produced and consumed efficiently.’<sup>109</sup>

This vision guided two decades of privatisation in both the wholesale and retail markets, leading Britain to have one of the most liberalised power markets in the world.

Yet nearly 50 years on we have turned decisively in the opposite direction. As we will see in the coming chapters, most new generation capacity will involve state subsidies in some way or another, whether it is renewables or nuclear or gas – not to mention novel technologies like CCUS and hydrogen.

Today, the Department for Energy Security and Net Zero (DESNZ) for the most part hand-picks the capacity mix – the market is no longer trusted to do so. Due to the need to plan transmission infrastructure, the state will decide where new generation will be sited.<sup>110</sup> And in the domestic market, the Government has quite literally reintroduced price controls, in the form of the energy price cap. What's most

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107 H. Cross, ‘Question for Department for Energy Security and Net Zero – Energy Company Obligation’, *UK Parliament*, February 2025. [Link](#)

108 ‘Conservatives launch Cut My Bills campaign’, *PolicyMogul*, November 2025. [Link](#)

109 House of Lords Economic Affairs Committee, ‘The Price of Power: Reforming the Electricity Market’, *UK Parliament*, 2017. [Link](#)

110 Determined according to the (yet to be released) Strategic Spatial Energy Plan, but exacerbated by the Government's Clean Power 2030 plans – see for example the outrage expressed by the solar industry over caps to their growth in the 2030 plans. ‘Strategic Spatial Energy Planning (SSEP)’, *National Energy System Operator*, 2026. [Link](#). G. Simkins, ‘Capping solar and battery storage risks £26bn investment’, *Solar Energy UK*, February 2025. [Link](#)



remarkable is that the party of Lawson was the architect of much of this, preaching the gospel of free markets while in practice embracing central planning.

Much of the blame for the Conservative Party's embrace of Leviathan has been laid at the door of decarbonisation. And it's certainly true that commercialising so many new low-carbon technologies in such a short period of time necessitated state support in some way or another.

But while decarbonisation is important, embracing state direction of the power market to such a huge degree has been essentially a political choice – a passive (and lazy) one on the part of the last Government, and an active one from the current Government.

This report will aim to show that new power stations – both renewables and nuclear – can be built without subsidies. And that although few realise it today, we will soon be entering a new era in our power system – one to which markets are far better suited than central planning.

**‘ By 2030, NESO expects demand on the grid to be 14% higher than in 2024; in 2035 it'll be 37% higher; in 2050 anywhere from 93% to 175% higher ’**

To understand why, it's helpful to return to the key statistic from Chapter 1: that total power demand has been in a gradual decline since the 2000s. Thus the renewable capacity we've added up until now has essentially been replacing older capacity – some of which would have been retired anyway, but much of which has been chucked because it puts out too much carbon.

Two trends are set to change all of this, however. The first is that the 'job' of decarbonising our power grid will soon be coming to an end. Whether the Government actually hits its Clean Power 2030 target or not (and we suspect not), the grid is set to be pretty well decarbonised by the early 2030s.

The second trend is that as more EVs, heat pumps, data centres and air conditioners come online, and industry electrifies, demand on the grid will start to go up. (In fact, it ticked up in both of the last two years, reversing the trend of the previous two decades.)<sup>111</sup>

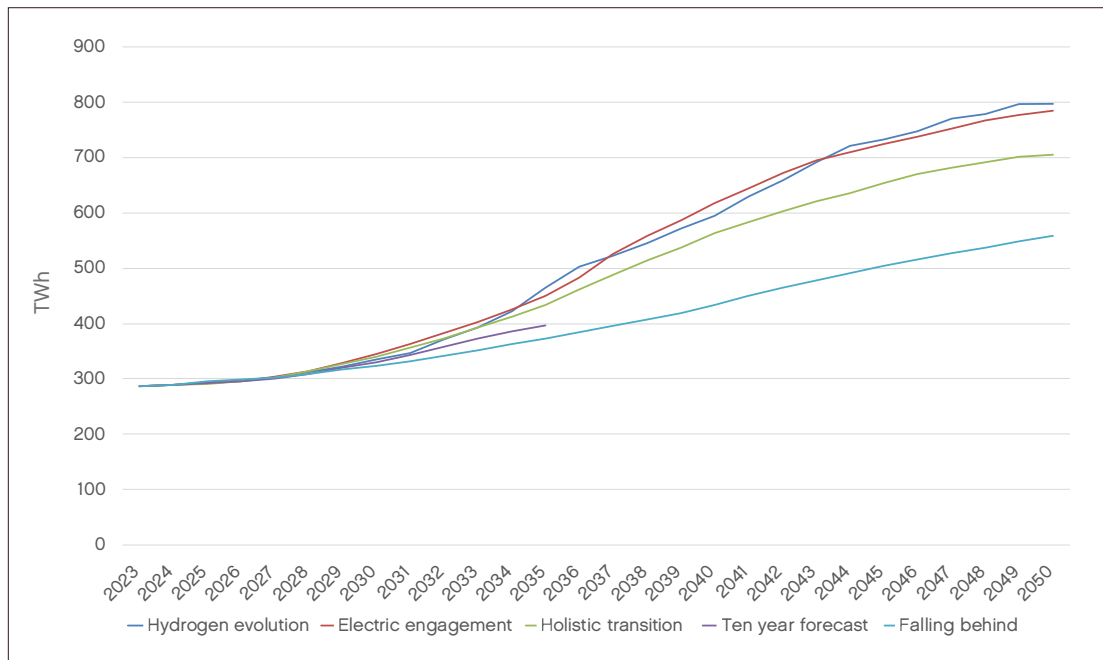
By 2030, NESO expects demand to be 14% higher than in 2024; in 2035 it'll be 37% higher; in 2050 anywhere from 93% to 175% higher.<sup>112</sup> To meet all of that extra demand will require new power stations of every type, all across the country.

111 S. Evans & H. Woo Nam, 'Analysis: UK renewables enjoy record year in 2025 – but gas still rises', *Carbon Brief*, January 2025. [Link](#)

112 Per FES 2025. Note the 2030 and 2035 figures use the 10 Year Forecast (NESO's best expectation), but the full range is 12%-19% for 2030 and 29%-60% for 2035 (the latter both include the 'Falling Behind' scenario where Net Zero is not reached).



## NESO forecasts for GB electricity demand, 2023-2050



Source: NESO Future Energy Scenarios<sup>113</sup>

In short, both of those trends combined mean that we'll soon be switching from building new capacity to replace existing generation (first coal, then gas) to adding substantial amounts to the grid.

This leads to a crucial difference – for the first time in a long time, growth in our power capacity will be led by demand, not by government mandates. There won't be any overriding ministerial desire to replace fossil fuels with low-carbon power, because successive governments will already have done that. Rather, homes and businesses across the country will find themselves in need of substantially more power than they've consumed historically. And in theory, the market will respond with new plants to supply them.

**‘ If we truly want households and businesses to enjoy energy abundance, then the essential prerequisite is cheap power ’**

The post-decarbonisation era opens up huge opportunities for the energy system, not least the ability to steer back towards the Lawson vision. Indeed, we would argue that this is not just possible, but necessary for our national prosperity.

For if this demand pickup is to happen at all – if we truly want households and businesses to enjoy energy abundance – then the essential prerequisite is cheap power. And as we will argue throughout this paper, the key to cheap power is markets, not central planning.

113 'Future Energy Scenarios: Pathways to Net Zero', *National Energy System Operator*, 2025. [Link](#). Refers to GBFES System Demand per page 45 of the report and tab ED1 of the Data Workbook.



## The key principles underlying a better vision for the future

In the chapters that follow, we will get into the policy detail of this transformation – and outline quite how dependent on subsidy and state direction each corner of the power market has become.

But before that, we want to lay out a more comprehensive vision here. Indeed, if we are to rally people around a better direction for the market, it's important to lay it out clearly.

So what are the key tenets of this vision? What do we want the system to look like in 2035 or 2040?

**‘ We want households and businesses ‘filling their boots’ with energy, underpinned by low costs and a diverse generation mix ’**

### **Energy abundance and cheap prices**

We want households and businesses ‘filling their boots’ with energy, underpinned by low costs and a diverse generation mix. We must become internationally competitive again, with electricity tariffs at least in line with the European average, but ideally ahead of France and Germany. We must unleash an abundance mindset throughout the country, bringing factories to our shores and air conditioning to our homes.

### **Markets will do a better job of picking the capacity mix than government – whether renewables, nuclear or new technologies**

Given that new generation will be coming online to respond to new sources of demand, growth should be demand-led, not centrally planned. To us, Nigel Lawson's vision still holds more than 40 years later – the private sector has better information, sharper signals and more inherent discipline to choose the cheapest generation mix. The private sector is also unencumbered by the political pressure or magical thinking that can influence Government decisions.

### **Subsidies should have sunsets**

While novel technologies will require Government support as they scale up, they should not be reliant on these over the longer term. The subsidies we are building today should have clear exit strategies built into them, providing a signal to the market that all technologies will have to stand on their own two feet once commercialised. While there are potentially exceptions to this (such as the largest-scale assets like GW-scale nuclear and offshore wind, which private markets may struggle to finance efficiently), these should be the exception rather than the norm.

### **All technologies should compete on a level playing field**

In order for competition to function effectively, all technologies and companies must bear the same set of risks and costs – and let the cheapest ones win out. Renewables, for example, must bear more of their upstream connection costs (as the Government is looking at doing), in the same way that new nuclear assets are responsible for their own decommissioning costs.<sup>114</sup>

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114 B. McAlinden, ‘Nuclear power and energy generation’, *Institution of Civil Engineers*, 2023. [Link](#)



For mature assets, risk should sit in the private sector, not be socialised via consumers.

We must move away from the era of the ‘Central Return Generating Board’ (to borrow a phrase from Arthur Downing of Octopus Energy).<sup>115</sup> The job of any market is to efficiently price risk, not to insulate private investors from it. While low capital costs are important, a myopic focus on them can lead to system inefficiencies and higher costs overall.

### **A more competitive domestic retail market**

We want a thriving retail market, underpinned by innovation and fierce competition, not the current thicket of overbearing regulations and price controls. The introduction of half-hourly settlement and secondary suppliers is sorely needed, along with a wider shake-up of the regulatory regime. While no one should be forced into a tariff that is not suitable for them, competition should be welcomed so long as flexibility remains voluntary and saves consumers money.

‘ **The job of any market is to efficiently price risk,  
not to insulate private investors from it** ’

### **Competition in our networks and sharper locational signals**

While the transmission and distribution systems are obviously more difficult to expose to competition than generation and retail, we can and should go further. The distribution networks are already well-served by independent operators that compete with the incumbents, while similar changes are coming to transmission – and should be encouraged. Meanwhile, transmission charging is in urgent need of reform. While the Government has decided against locational pricing for now, we still believe it is the right decision over the longer term.

### **Government’s primary role should be ensuring security of supply**

While we should want as much competition in the system as possible, there will always be a role for Government in ensuring that the lights stay on. Indeed, Ofgem and NESO work to strict ‘security of supply’ standards, and Government has tools such as the Capacity Market to ensure enough supply is available when needed. This work must be maintained, including with additional gas capacity where necessary – the buck ultimately stops with ministers to prevent blackouts, as well it should.

In the next few chapters, we will set out the state of the energy system, and how these principles could apply – starting with renewables.

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<sup>115</sup> Who Kept the Lights On?, ‘The myth of the central planner’, *Energy Networks Substack*, July 2024. [Link](#)



# Chapter 3: Renewables – from Subsidies to Self-Reliance

## Introduction

The last few years have seen something of a backlash on the right against renewables. Reform UK are outright opposed to ‘Net Stupid Zero’ and all that comes with it.<sup>116</sup> And the Conservatives, who helped to bring down the cost of offshore wind via the introduction of the CfD, have begun to express almost equal scepticism. Given that the dire state of our power markets in the last few years coincides with record growth in renewables on our grid, some have concluded that renewables are fatally flawed.

In some ways, the green lobby bears much of the blame for this turn of events. For too long any criticism of renewables was dismissed as Net Zero scepticism, rather than an attempt to genuinely reckon with the pros and cons of wind and solar.

**‘ The last few years have seen something of a backlash on the right against renewables. Reform UK are outright opposed to ‘Net Stupid Zero’ and all that comes with it ’**

Renewables absolutely have their flaws. They are intermittent, require substantial grid build-out to accommodate, and have quite a different cost profile to the one our systems were designed for – and of course the headline price of their energy does not include either transmission costs or the back-up to compensate for that intermittency.

But they also have their strengths: they are easily deployed, relatively quick to build, and can deliver energy at near zero marginal cost when the wind is blowing or the sun is shining (and in the North Sea, the wind is blowing frequently).

Perhaps the main problem renewables face is the perception that they are entirely dependent on subsidies. A piece in the Telegraph recently argued: ‘Indeed, the so-called renewables industry is not a business in any meaningful sense of the word: it only exists because of subsidy and government regulation and therefore destroys value for the country rather than creates it.’<sup>117</sup>

But this perception is wrong. In fact, there is a strong private market for renewables in the UK and around the world, in the form of Power Purchase Agreements (PPAs). Driven primarily by corporate demand, solar farms in particular are getting built without Government contracts up and down the country.

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<sup>116</sup> ‘Reform would scrap “net stupid zero” policies, says deputy leader’, *BBC News*, March 2025. [Link](#)

<sup>117</sup> D. Frost, ‘The awful truth about Labour? They’re continuity Sunak’, *Telegraph*, July 2025. [Link](#)



In many ways this is exactly what should be happening – as we will see, the CfD was never meant to be permanent. Rather it was envisaged as a way to scale up renewables, after which subsidies would be withdrawn. And if renewables can be deployed on a truly cost-competitive basis, many of the objections to them fall away.

Sadly, as we will see in this chapter, government policy means we are far away from the end of subsidies – and getting further so.

‘ The ‘load factor’, or percentage of the year in which an asset generated power, was 39% for offshore wind over 2022-24, 26% for onshore wind and 10% for solar ’

## Wind and solar – the strengths and weaknesses

### *Intermittency*

The weaknesses of renewables are well-worn, but they do bear repeating, particularly as some are rather misunderstood.

The obvious place to start is their intermittency. Put simply, generation from wind and solar assets is weather-dependent and thus not always available.

The statistics are rather remarkable on this front. The ‘load factor’, or percentage of the year in which an asset generated power, was 39% for offshore wind over 2022-24, 26% for onshore wind and 10% for solar.<sup>118</sup> As a point of comparison, nuclear’s load factor in 2024 was 72%, with the downtime primarily for refuelling and maintenance.<sup>119</sup>

Thus, as is commonly pointed out, renewables require ‘backfilling’ by another asset that can generate power when needed (‘dispatchable power’) – which in today’s system is primarily gas.

What is often overlooked in the discussion of intermittency, however, is that demand itself is quite variable. It typically peaks in the morning and the evening during the working week, and is lower during the weekends, as the below graph shows.

Demand is also quite seasonal – higher in the winter than the summer given shorter days, the need for heat, and our general lack of air conditioning. Thus the highest demand in 2025 was at 5.00pm on 9 January (at 46 GW), while the lowest was at 1.30pm on 25 May (13 GW).<sup>120</sup>

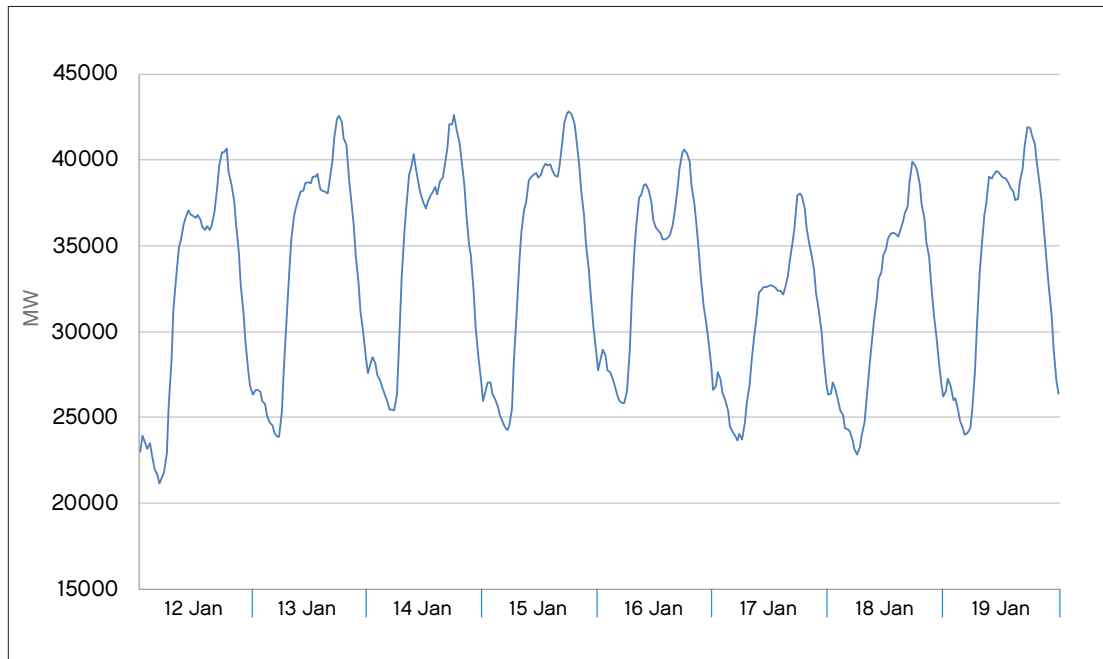
118 Note defined precisely this is the percentage of actual generation relative to maximum possible generation over the course of a year. Load factors for renewable electricity generation (DUKES 6.3) ‘Digest of UK Energy Statistics (DUKES): renewable sources of energy’, *Department for Energy Security & Net Zero*, July 2012. [Link](#)

119 ‘DUKES 2025 Chapter 5: Electricity’, *Department for Energy Security and Net Zero*, July 2025. [Link](#)

120 ‘Britain’s Electricity Explained: 2025 Review’, *National Energy System Operator*, January 2026. [Link](#)



## Power demand for week commencing 12 January 2026



Source: Elexon<sup>121</sup>

In other words, some variability in the system is actually helpful – the trick is matching your generation profile to your demand profile. So how well does our current mix of renewables do this?

Well, this past June, wind generated 31% of our electricity, and solar 12%, topped up by gas (18%) and nuclear & imports (15% respectively).<sup>122</sup> Compare that to last January, where wind generated 27% of our power and solar only 2%, with gas at 38% and nuclear & imports at 12% respectively.<sup>123</sup>

Solar in the UK generates in line with demand on a daily basis, because demand is higher in the day, but inversely on a seasonal basis – high in the summer when demand is lower, and vice versa in the winter. (Though if air conditioning takes off, this pattern could shift.)<sup>124</sup>

That said, at our high latitudes there's not as much sun to go around – compare our solar load factor of 10% to California's 27%.<sup>125</sup> Wind on the other hand has a more consistent yearly profile, though it is more unpredictable than solar's steady rhythms.<sup>126</sup>

Of course, the ultimate nemesis for renewables is what's known as *Dunkelflaute* – the times in the winter where the wind is still and the days are short and cloudy. These bleak spells can last for days at a time, or even one or two weeks – and tend to arrive at just the time of year when demand is highest.

<sup>121</sup> 'Demand Outturn', *Elexon (BMRS)*, 2025. [Link](#) (Note using INDO)

<sup>122</sup> 'Britain's Energy Explained: How was our electricity generated?', *National Energy System Operator*, June 2025. [Link](#)

<sup>123</sup> 'Clean Power 2030 Implementation Plan', *National Energy System Operator*, January 2025. [Link](#)

<sup>124</sup> M. Geocaris, 'Summer 2024 Was One for the Power Grid History Books', *National Laboratory of the Rockies (NREL)*, November 2024. [Link](#)

<sup>125</sup> T. Lenoir, '2022 monthly US solar capacity factors underscore winter doldrums', *S&P Global Market Intelligence*, October 2023. [Link](#)

<sup>126</sup> 'Wind Energy: implications of large-scale deployment on the GB electricity system', *Royal Academy of Engineering*, April 2014. [Link](#)



This means that a substantial fleet of gas power stations is required to be on standby. Indeed, a remarkable fact about Labour's 2030 plan is that the amount of gas capacity on the system will remain roughly the same as today, at 35 GW.<sup>127</sup> It's just that its utilisation will decrease hugely, from 26% in 2024 to 5% or below.<sup>128</sup>

That said, this risk has led in some quarters to the assumption that renewables will need a 100% backup system, essentially doubling the cost of the power system. This belief is wrong, for several reasons. First, even during a Dunkelflaute, renewables do generate power, albeit nowhere near their maximum capacity (during one such episode on 8 January last year, wind was generating 7% of our power).<sup>129</sup> This will grow further as the take-up of renewables increases, and of course there are other sources to pick up the slack.

Indeed, on that day (at 5pm) gas was only generating 53% of our power, with the rest being made up of imports, nuclear, wind, biomass, storage and hydroelectric (in that order).<sup>130</sup> And these other sources will continue to grow – for example while there is only 6.9 GW of battery storage online (as of September 2025), another 6.5GW is under construction and over 60GW is consented.<sup>131</sup>

Admittedly, most of this storage is relatively shorter-term, holding its charge for a matter of hours rather than the days or weeks of storage that would be required to more substantially phase out gas. But even in their current state of development, batteries can play a valuable role in balancing energy demand across the day: in California, the 16 GW of batteries that are currently deployed can provide as much as 30% of electricity demand at the daily peak around 8pm, shifting excess generation from earlier in the day to when it is most needed.<sup>132</sup>

Whether it is via better batteries, flexible demand, applying carbon capture technology (CCUS) to gas-fired power stations, retrofitting them with hydrogen, or building new nuclear, there are potential clean solutions to the intermittency problem on the horizon. But for the moment, maintaining the gas fleet is certainly critical to backfilling for the intermittency of renewables. So what are the cost implications?

Well, for the most part, it depends on the cost of the power being used to 'backfill', which can vary substantially. But there are also secondary effects. As one might expect, an increasing reliance on weather-dependent renewables has increased the costs NESO incurs to balance the system, from £7 on the average household bill in 2017 to ~£30-40 in recent years.<sup>133</sup> Though the largest driver of that increase was constraints on the grid (discussed further below), rather than intermittency per se.<sup>134</sup>

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127 'Clean Power 2030 Action Plan: A new era of clean electricity – main report', *Department for Energy Security & Net Zero*, December 2024. [Link](#)

128 'Britain's Electricity Explained: 2024 Review', *National Energy System Operator*, January 2025. [Link](#)

129 At 5pm on 8 January 2025. 'Historic GB Generation Mix', *National Energy System Operator*, 2025. [Link](#). 'State of the Climate for the UK Energy Sector 2024-25', *Royal Meteorological Society*, 2025. [Link](#)

130 Ibid.

131 D. Sutherland, 'Stacking up the storage: where the UK battery market stands in 2025' *RenewableUK* (Energy Pulse Blog), September 2025. [Link](#).

132 'California has got really good at building giant batteries', *The Economist*, May 2025. [Link](#)

133 'Balancing costs', *National Energy System Operator*, 2025. [Link](#)

134 'Annual Balancing Costs Report 2025', *National Energy System Operator*, January 2025. [Link](#) Page 18



Running gas power stations less and less frequently also has a cost, which is borne in what's known as the Capacity Market.

Gas power stations (and increasingly batteries and other technologies) receive 'capacity payments' simply for being available, in addition to the revenue they receive for generating power.<sup>135</sup> These charges are then added to consumer bills, accounting for £19 per household in 2024.<sup>136</sup> (It should be noted here that fully assigning these costs to renewables is somewhat difficult – even if our grid mix was mostly nuclear, we would still require some flexible capacity to manage demand peaks or outages. Even France, with its abundant nuclear generation, has a capacity mechanism.)<sup>137</sup>

This sort of mechanism is not the only way to manage security of supply. Texas famously has an 'energy-only' market, in which those stations that supply power are paid only when they actually supply power, and prices are set almost entirely to the laws of supply and demand. For supporters of the free market, this is an attractive idea – but it does also mean that prices are allowed to rise to nosebleed levels (previously \$9,000/MWh and now \$5,000/MWh) to let gas power plants recover their costs in times of extreme scarcity.<sup>138</sup> In Britain, by contrast, the Balancing Mechanism never lets prices go this high, creating the issue of 'missing money' which the Capacity Market was brought in to solve.<sup>139</sup>

**‘ To get to a cheaper system, we need both renewables that are genuinely cheap, and to ensure that the buyer of the power understands the full costs ’**

To sum up, intermittency is absolutely a key downside of renewables. Today it is topped up by gas, tomorrow it will be a combination of gas and other technologies, including long-duration storage, plus demand flexibility. To get to a cheaper system, we need both renewables that are genuinely cheap, and to ensure that the buyer of the power understands the full costs.

### *Cost profile*

Another key aspect of renewables is that they have a fundamentally different cost profile to gas and coal. Gas, for example, has moderate upfront costs to build the station, coupled with fluctuating fuel costs dependent on prevailing gas and carbon prices.<sup>140</sup> Renewables have high upfront costs, in terms of building the panels or turbines, but low ongoing costs, given their 'fuel' is the wind and the sun.

As a result, renewables are both highly dependent on the cost of capital (the combination of debt and equity used to finance the construction), and are generally

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135 K. Ross, 'NESO releases provisional T-4 Capacity Market Auction results', *Solar Power Portal*, March 2025. [Link](#)  
'Capacity Market: 10-year review (2019 to 2024)', *Department for Energy Security & Net Zero*, December 2024. [Link](#). 'Schemes (Capacity Market, Contracts for Difference, Nuclear RAB)', *EMR Settlement Limited*, 2025. [Link](#)

136 'Balancing costs', *National Energy System Operator*, 2025. [Link](#)

137 E. Albertoli, 'The other Electricity Cash Cow: the Capacity Mechanism', *Haya Energy Solutions*, January 2024. [Link](#)

138 'Review of the ERCOT Scarcity Pricing Mechanism', *Public Utility Commission of Texas*, March 2022. [Link](#)

139 'Electricity Market Reform – Capacity Market (Impact Assessment)', *Department of Energy & Climate Change*, November 2012. [Link](#)

140 E. Hezlet, 'UK Gas Power Stations: Capital Costs', *Watt Direction*, January 2023. [Link](#)



'price-takers' in the wholesale market, given that the marginal cost to produce an additional unit of electricity is at or near zero. Indeed, their incentive is always to run as much as possible and take whatever price they can get to repay their capital costs (or maximise the value of their subsidy, as discussed below).

This also means that once the debt has been paid down, and/or the subsidy has expired, the energy produced is pretty cheap. DESNZ estimates ongoing operational expenses (for new projects) to range from £9/MWh for large-scale solar to £34/MWh for offshore wind – though hard data on this is difficult to come by, particularly for older assets.<sup>141</sup>

In itself this cost structure isn't a problem. The issue is that it isn't the one our markets were designed to accommodate.

The structure of the power market is a product of the 'NETA' reforms in 2001, when our mix was primarily coal, gas and nuclear.<sup>142</sup> The market was therefore set up to function on the basis of short-run marginal cost, as with many commodity markets around the world – in essence, the most expensive unit of supply needed to meet demand sets the price.

**‘ In itself, the cost structure of renewables isn't a problem. The issue is that it isn't the one our energy markets were designed to accommodate ’**

For assets like gas and coal, this was a sensible way to organise things – different fuels and individual stations have varying cost structures, and thus 'price discovery' finds the optimal clearing price for a given level of demand. But for renewables, short-run marginal cost is not representative of their overall cost profile. Even though their short-run costs are quite low, their long-run costs are much higher, for as long as they've got a large debt to repay. (To be fair, gas plants find it difficult to recover their costs in the current market structure given lower running hours, necessitating the Capacity Market, as discussed above and in Chapter 6.)

To build out renewables, investors have demanded 'price stabilisation' mechanisms to guarantee they receive their long-run price, whether funded publicly via CfDs, or privately via PPAs. Renewables have thus been 'bolted on' to a market that wasn't designed for them, leading to substantial tension. (In the REMA process – the Review of Electricity Market Arrangements – fundamental reforms to the structure of the market were considered to take account of these differences, but were ultimately dismissed as being unworkable for a variety of reasons.)<sup>143</sup>

141 For stations commissioning in 2030. 'Electricity Generation Costs 2025', *Department for Energy Security & Net Zero*, January 2026. [Link](#)

142 D. Currie, 'The New Electricity Trading Arrangements in England and Wales', *Institute of Economic Affairs*, October 2000. [Link](#). T. McGarry, 'UK Electricity capacity and generation by fuel between 1920 and 2020', *Department for Energy Security & Net Zero*, June 2023. [Link](#)

143 'Review of electricity market arrangements (REMA): second consultation', *Department for Energy Security & Net Zero*, March 2024. [Link](#)



## *Inertia & voltage control*

Inertia and voltage control present additional challenges as electricity systems rely more heavily on renewables. Traditionally, large power stations such as coal, gas and nuclear plants helped keep the grid stable simply by operating: their heavy spinning machinery provided inertia, which slows sudden changes in frequency, and helped regulate voltage, keeping electricity flowing reliably across the network.

Wind and solar connect to the grid through power electronics rather than large rotating machines. They do not inherently provide the same physical inertia, and while modern wind and solar in Great Britain are now required to support frequency and voltage through Grid Code standards, these services no longer come automatically with generation. As a result, they must be deliberately specified, assured and, in some cases, procured.

NESO has long planned for this transition and now actively manages inertia and voltage control through dedicated arrangements, including synchronous condensers, grid-forming technologies and new stability services.<sup>144</sup> However, the Iberian blackout last year is a terrifying reminder of what can potentially go wrong.<sup>145</sup>

**‘ Wind and solar connect to the grid through power electronics rather than large rotating machines. They do not inherently provide the same physical inertia ’**

## *Individual downsides for wind and solar*

Though usually grouped together, wind and solar are different technologies and do have their own individual downsides. Wind farms are often sited far from demand, given that it's windiest in the North of England, Scotland and the North Sea, not in London and the Midlands.<sup>146</sup> To transport the electricity to where it will be used, the grid operator must undertake a substantial build-out of new transmission lines, the costs of which land on consumer bills to a large extent (£51 per household in 2025/26, forecast to rise to £79 by 2029/30).<sup>147</sup>

Furthermore, because transmission lines haven't kept pace with generation, NESO is forced to pay substantial 'constraint' payments when the grid can't handle all the power. In a typical example, a wind farm in Scotland will be paid to turn off, while a gas power station in England will be paid to turn on. This too lands on consumer bills – total balancing costs in 2024/25 were £30 per household, or £2.7bn in total, of which constraints made up £1.7bn. NESO believes constraints could continue to rise in the coming years, peaking in 2030 as the graph below shows.<sup>148</sup>

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144 'Stability Market', *National Energy System Operator*, 2024. [Link](#). 'Reactive Power Market', *National Energy System Operator*, 2024. [Link](#)

145 'Future-Proofing GB's Power System: Reflections on the April 2025 Iberian Event', *National Energy System Operator*, 2025. [Link](#)

146 'Global Wind Atlas', *Energydata.info*, 2026. [Link](#)

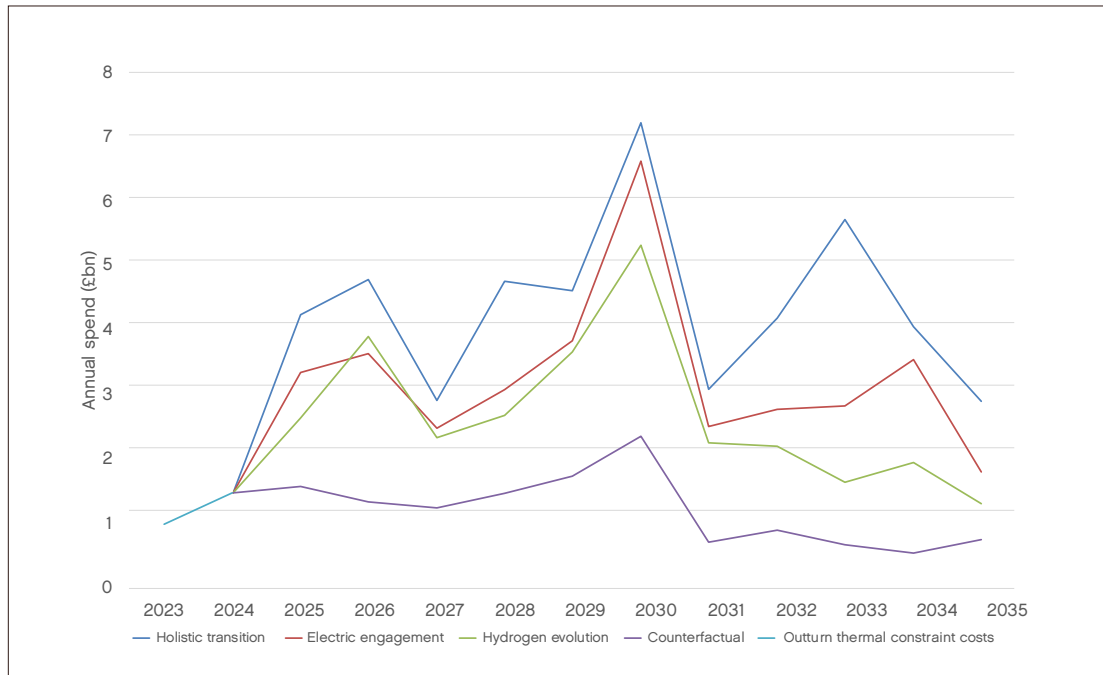
147 Note that TNUoS covers the cost of maintaining the existing network as well as building out new transmission lines. NESO Revenue Team, 'Final TNUoS Tariffs for 2025/26 – Webinar', *National Energy System Operator*, February 2025. [Link](#). 'TNUoS Tariffs Five Year Projection for 2029/30-2033/34', *National Energy System Operator*, September 2023. [Link](#)

148 2025 Annual Balancing Costs Report', *National Energy System Operator*, June 2025. [Link](#) and [Link](#)



Both of these factors add further to the overall cost of new renewable generation, and in particularly wind generation – though it is worth noting that to some extent they are the product of how we have designed the system, as will be discussed further in Chapter 6.

### Forecasts for GB constraint payments, 2023-2035



Source: NESO<sup>149</sup>

Solar is often closer to demand, reducing the need for new transmission lines. However, larger solar farms can take up substantial amounts of land, often running into local opposition in the process. Of course, context is key – solar farms today take up 0.07% of total UK land, and at worst are projected to take up 0.72% by 2050, or 1.5% of agricultural land (for context, golf courses currently use 0.51% of available land).<sup>150</sup> However, the spatial distribution of solar farms is uneven. The majority of them are located in England and are set to cover 0.78% of English land by the end of the decade.<sup>151</sup> In some constituencies, the solar footprint is particularly acute – reaching up to 9% of the total area in Newark, much of it on the highest grade of farmland. In fact, 31% of England’s largest operational solar farms are located on such pastures.<sup>152</sup>

The Government is currently working on a Land Use Framework which aims to prevent high quality farmland from being diverted from agricultural use. However, it is important to highlight that solar farms can still be used for livestock grazing, leading to the emerging industry of ‘agrivoltaics’.<sup>153</sup> This is why the NFU is generally supportive of solar farms, as an extra income stream for its members: president Tom Bradshaw notes that ‘it is a small amount of land which is being taken out of production’<sup>154</sup>, while

149 ‘2025 Annual Balancing Costs Report’, National Energy System Operator, June 2025. [Link](#) (Page 55)

150 ‘Researchers use satellite imagery to shed light on UK solar farm land use’, *Lancaster University*, July 2024. [Link](#)

151 W. Humphries, ‘Wild West’ planning leaves solar farms clustered on prime land’, *The Times*, October 2025. [Link](#)

152 Ibid.

153 H.Horton, ‘Land use plan for England maps out farming, nature, housing and solar/wind’, *The Guardian*, January 2025. [Link](#). M. Green, ‘Mythbusting solar PV’s impact on agricultural land’, *Solar Media Ltd*, March 2023. [Link](#). M. Christian, ‘Agrivoltaic solar farms: how they work and why they matter’, *AquaSwitch*, 2024. [Link](#)

154 M. Green, ‘Miliband and Solar Energy UK quell solar farm food security fears’, *Solar Media Ltd*, April 2024. [Link](#)



his colleague Jonathan Scurlock argues that ‘there is no threat to national food security from solar’.<sup>155</sup>

Undoubtedly, solar farms (and onshore wind farms) can generate substantial local resistance. Those living nearby can understandably be concerned about the impact on the visual landscape, and want a voice in the development process. The Government is currently consulting on the introduction of a mandatory community benefits scheme, which would provide flexible funding to local communities hosting new energy infrastructure.<sup>156</sup> However, it is worth noting that opposition may not be fully representative of local opinion: polling shows that among rural voters, 64% would be supportive of a new solar farm being built in their local area, and 58% of new onshore wind.<sup>157</sup>

### *Cost profile*

For all of the flaws above, renewables do absolutely have their strengths. For starters, unlike gas, coal or nuclear, a solar panel requires no fuel – only the cost to administer the plant and the occasional maintenance.

Thus, as discussed above, once the associated costs have been paid back, the power coming from a solar or wind farm is genuinely pretty cheap. And as technology has improved, the payback period for the upfront investment has continued to decrease. A business installing solar panels will now see its upfront costs recouped in 5-10 years through savings on its power bill – after which the savings continue to pile up over the life of the asset (in the case of solar panels, c. 25 years).<sup>158</sup>

‘ A recent report from the Energy & Climate Intelligence Unit found that wind farms cut wholesale (day-ahead) electricity prices by approximately 25% in 2024 ’

### *Effect on wholesale prices*

Another, underappreciated facet of renewables is their effect on wholesale prices.

While renewables do receive subsidies outside of the wholesale market (discussed further below), they have the effect of dragging prices in the wholesale market down by virtue of the fact that they have zero marginal costs. That’s to say, a wind or solar farm with no fuel cost can outbid other technologies such as gas and biomass, pulling down the prices that clear the market.

Moreover, since all gas power plants are not created equal – those that are less efficient, requiring more gas per unit of electricity, will cost more – renewables that displace these expensive facilities will still bring down prices. A recent report from

155 ‘Factcheck: 16 misleading myths about solar power’, *Carbon Brief*, August 2025. [Link](#)

156 ‘Community benefits and shared ownership for low-carbon energy infrastructure: Working paper’, *Department for Energy Security & Net Zero*, May 2025. [Link](#)

157 G. Smeeton, ‘Election poll: swing rural voters show higher support for net zero and climate action’, *Energy and Climate Intelligence Unit*, May 2024. [Link](#)

158 J. Richardson, ‘Power Your UK Business with Commercial Solar Panels’, *Renewable Energy Hub*, June 2025. [Link](#). B. Westcott & J. Brimblecombe, ‘What is the payback period for commercial solar panels?’, *Eden Sustainable*, February 2025. [Link](#)



the Energy & Climate Intelligence Unit found that wind farms cut wholesale (day-ahead) electricity prices by approximately 25% in 2024.<sup>159</sup>

While this won't affect generators with a CfD (which get paid their strike price regardless of the wholesale price), it will reduce revenues, and thus bills to consumers, for other generators exposed to wholesale prices, such as nuclear power stations or renewables on the older Renewables Obligation scheme.

### *Speed to build*

Another big advantage of wind and solar is that they're relatively quick to get up and running. Large-scale solar can be built in as little as one year, with rooftop deployment even quicker (though pre-development will take time as well).<sup>160</sup> Wind takes longer, currently 4-9 years for onshore from inception to operation, but the Government is aiming to cut this time substantially given much of the time needed is for planning, consenting and grid connections.<sup>161</sup> Indeed, Octopus Energy recently built a (temporary) wind turbine in Hackney in just two days, using it to power food trucks.<sup>162</sup>

**‘Solar farms can be constructed in 6-12 months, and even with planning and grid connections the total time is often less than two years’**

By comparison Sizewell C will take at least a decade to construct, and first submitted a planning application in 2020.<sup>163</sup> And even gas stations are not as quick to construct as their reputation suggests, as discussed below.

Speed to build is particularly important because of rising demand. As mentioned repeatedly, the renewable capacity we've added up until now has essentially been replacing older capacity. But if demand does ramp up as NESO expects, we will need new capacity relatively quickly.

Obviously NESO's projections are only projections, and they depend on consumers and businesses choosing to buy EVs and heat pumps and so on. But in the immediate term, it's difficult to see what other than renewables could meet the bulk of this rise in demand.

### *Energy security*

Finally, it's worth thinking about energy security. On this, renewables do not fit neatly into either the 'pro' or 'con' box. On the one hand, China dominates the supply chain for solar power (and wind to a lesser extent), with accusations of forced labour

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<sup>159</sup> Relative to a counterfactual scenario without large-scale wind capacity. 'Marginal Gains: How wind is pushing gas out of the power market and cutting costs', *Energy & Climate Intelligence Unit*, October 2025. [Link](#)

<sup>160</sup> 'Solar roadmap: United Kingdom powered by solar', *Department for Energy Security & Net Zero*, June 2025. [Link](#)

<sup>161</sup> 'Onshore Wind Taskforce strategy', *Department for Energy Security & Net Zero*, July 2025. [Link](#)

<sup>162</sup> J. Murray, 'Hackney wind turbine erected in just two days', *BusinessGreen*, November 2024. [Link](#)

<sup>163</sup> A. Cunningham, 'Sizewell C nuclear plant gets £14bn go-ahead from government', *BBC News*, June 2025. [Link](#)



aplenty.<sup>164</sup> A disturbing report from Reuters uncovered rogue communication devices in some Chinese solar power inverters in the US, raising the possibility that they could be used as remote 'kill switches'. Mike Rogers, a former director of the U.S. National Security Agency, told Reuters: 'We know that China believes there is value in placing at least some elements of our core infrastructure at risk of destruction or disruption...[in order to] limit the options that the West has to deal with the security issue.'<sup>165</sup>

On the other hand, once the kit is up and running, renewables aren't dependent on fuel markets like gas and oil (and uranium to a lesser extent) – and the Ukraine crisis laid bare our current energy insecurity.

Moreover, while gas and electricity cables in the sea are vulnerable to sabotage, the renewables themselves are more resilient by virtue of being distributed: taking out a single wind turbine or solar panel would do little to undermine the grid, whereas taking out a gas plant would remove a substantial block of supply at once.

In truth, in practice the most critical vulnerabilities lie in infrastructure that is shared by all types of power generation, such as cables, substations and control systems, rather than in individual generating assets.

**‘ While gas and electricity cables in the sea are vulnerable to sabotage, the renewables themselves are more resilient by virtue of being distributed ’**

## The subsidy-dependence of renewables

So far we have discussed the pros and cons of renewables purely on their own terms. However, there is one glaring omission from the previous section – the role of subsidies in underpinning renewables deployment.

For many on the right, this is the crux of the issue: renewables are supposedly the cheapest technology around. Yet they seem to be permanently dependent on subsidies. Shouldn't they be able to stand on their own two feet at this point?

The short answer is – they are, and most of Westminster has no idea. This is a key issue that this paper will seek to address – contrary to popular belief, renewables (particularly solar farms) are being built all over the country without a government contract.

This paper will thus argue that, while renewables can play a big role in the abundance agenda, we need to push the Government harder to wean them off subsidies.

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164 'Solar PV Global Supply Chains (Executive Summary)', *International Energy Agency*, July 2022. [Link](#). 'Can we achieve Net Zero without China?', *Britain Remade*, December 2025. [Link](#). I. Ukpanah, 'Solar companies linked to forced labour continue to grow steadily in popularity despite government actions', *GreenMatch*, March 2024. [Link](#)

165 S. McFarlane, 'Rogue communication devices found in Chinese solar power inverters', *Reuters*, May 2025. [Link](#)



To flesh out this vision, it's helpful to understand the current subsidy regime, and why renewables remain (to a large extent) dependent on them after so many years.

The Contracts for Difference (CfD) regime was introduced by the Coalition as a replacement for the ailing Renewables Obligation. To simplify, the previous scheme gave renewable generators a subsidy payment (market-driven, but over-engineered) alongside the revenue they would normally receive in the wholesale market.

For developing technologies with high upfront costs and low marginal prices the Renewables Obligation was a bad fit, particularly for larger offshore wind projects. That is to say, the level of combined revenues received by generators was so volatile that investors would only lend at relatively high rates – meaning renewables were expensive and too little was deployed.<sup>166</sup>

The CfD overhauled this by guaranteeing the price that generators would receive – effectively 'solving' the price-taker issue. While generation was still dependent on weather patterns, investors could be much more confident in the financial profile of a new wind farm. That meant the cost of capital could come down. And so it did, particularly for offshore wind – famously reducing from £120/MWh in 2015 to £37/MWh in 2022 (in 2012 prices).<sup>167</sup>

**‘ The CfD was never meant to be a permanent intervention. Its designers saw it as a bridge to help nascent technologies scale up – at which point it would eventually fall away ’**

Of course, this wasn't just about CfDs. Global trends in cost reduction and supply chain maturity also played a large role. And in the last few years strike prices have increased from their lows in 2022, driven by supply chain pressures and higher interest rates (and the Government's reckless 2030 sprint).

However, what is mostly forgotten today is that the CfD was never meant to be a permanent intervention. Its designers saw it as a bridge to help nascent technologies scale up – at which point it would eventually fall away.

The policy overview put out when the relevant Bill was introduced to Parliament in November 2012 makes this quite clear: 'At some point in this stage [late 2020s and beyond], it should be possible for the Government to stop issuing CfDs, as the wholesale market (and Capacity Market) would be sufficient to support ongoing investment in low-carbon technologies, and to deliver the UK's 2050 decarbonisation target and determine the optimal mix of technologies at least cost.'<sup>168</sup>

The paper conceded that for this to happen, several conditions would need to be met: a high enough carbon price to stimulate investment, a decline in technology

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166 'Electricity Market Reform', *Department of Energy & Climate Change*, December 2010, p.55, box 5. [Link](#)

167 Generation from its first three allocation rounds saved consumers an estimated £3bn up to 2020 in comparison with supporting the same projects under the Renewables Obligation (RO). 'Evaluation of the contracts for difference scheme – Allocation Round 3', *Department for Business, Energy & Industrial Strategy (BEIS)*, November 2020. [Link](#). Note ARI saw offshore wind prices of £120/MWh for 2017/18 delivery and £114/MWh for 2018/19 delivery. 'Contracts for Difference Allocation Round 4 results', *Department for Business, Energy and Industrial Strategy*, July 2022. [Link](#)

168 'Electricity Market Reform: Policy Overview', *Department of Energy and Climate Change*, November 2012, p.28. [Link](#)



costs and a sufficiently diverse portfolio of technologies, alongside the ability to hedge electricity price risk over a longer period.

Most of the above conditions have now been met. But the vision of CfDs as a time-limited necessity has essentially disappeared from energy policy.

Carbon prices have indeed risen, from ~£9/tonne in 2012 to ~£60 today (alongside an extra £18 supplement for gas-fired power generators). Technology costs for wind and solar have decreased substantially, recent years notwithstanding. Solar, onshore wind and offshore wind are all sufficiently commercialised.<sup>169</sup> And yet, CfDs seem to be going nowhere.

In researching this paper, we have had numerous discussions with industry and policymakers. The strong consensus is that the CfD is, and under Labour will continue to be, the main vehicle for building new renewables, particularly offshore wind. Even for existing renewables which require ‘repowering’ (upgrading the kit at the end of a plant’s useful life), CfDs are to be the main mechanism: the Government has recently announced that repowered onshore wind will be eligible for CfDs, and is open to other technologies in future.<sup>170</sup> As far as we can tell, there are no active discussions in Government about moving away from a subsidised model, despite that being the original intent of the policy.

But it raises the question – given that these technologies are now unquestionably ‘mature’, why has the CfD become a fact of life in our energy policy?

**‘As far as we can tell, there are no active discussions in Government about moving away from a subsidised model, despite that being the original intent of the policy’**

## Why CfDs have stuck around

There is no single answer to this question. But the place to start is undoubtedly the price stabilisation feature.

The core of the issue is that renewables are currently unwilling to take on long-term price risk in an economically efficient manner. Somewhat presciently, the designers of the regime mentioned specifically that ‘the ability to hedge electricity price risk over a longer period’ would be important for the end of the CfD. Today, forward liquidity in the wholesale market does not extend much beyond a few years – certainly not long enough for a grid-scale renewable asset to repay its capital costs.<sup>171</sup>

There are compounding factors to add to this. The increasing penetration of renewables and batteries is expected to drag down wholesale prices later

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169 M. Roser, ‘Why did renewables become so cheap so fast?’, *Our World in Data*, December 2020. [Link](#). ‘Carbon Price Viewer’, *Sandbag Climate Campaign*, 2025. [Link](#). ‘European electricity prices and costs’, *Ember*, 2025. [Link](#). H. Ritchie, ‘Solar panel prices have fallen by around 20% every time global capacity doubled’, *Our World in Data*, June 2024. [Link](#)

170 ‘Policy considerations for future rounds of the Contracts for Difference scheme: government response’, *Department for Energy Security & Net Zero*, October 2024. [Link](#)

171 ‘Summary of Responses: Power Market Liquidity Call for Input’, *Ofgem*, August 2024. [Link](#)



this decade and into the next.<sup>172</sup> And one mechanism which drives this is the phenomenon of ‘cannibalisation’, whereby in particularly sunny or windy periods, the correlation of weather patterns will mean a huge glut of power, dragging prices to rock-bottom.<sup>173</sup> So not only will overall prices be lower (at least in wholesale terms, which of course is not the same as the actual price for consumers), but the prices actually earned by renewables will be lower than average because of this cannibalisation.

In other words, given low forward liquidity, volatile market conditions and an expectation of future price declines, few investors would put money into a renewable project (on a standalone basis) without some form of price guarantee behind it.

The second reason for the persistence of CfDs is the decarbonisation mission. Though few remember it today, onshore wind and solar were in fact excluded from the second and third CfD auction rounds, and forced to find private markets for their power.

Granted, part of the reasoning was the Conservative Party’s antipathy to onshore wind, due to a perception that it was unpopular with local communities. But the sentiment that renewables should be able to compete on their own was a motivating factor as well. As BEIS Secretary Greg Clark put it at the time: ‘We are now entering a world in which green power need not be subsidised.’<sup>174</sup>

**‘ The pace of decarbonisation was the driving factor in readmitting solar and onshore wind to the CfD auction, cutting off purely market-based decision-making at the knees ’**

While PPA deals did get done in the three years that solar and onshore wind were excluded, the momentum behind subsidy-free renewables ended with the Johnson government. ‘We are aware of a number of projects... that have deployed or are planning to deploy on a merchant [subsidy-free] basis,’ said the Government at the time. ‘However, there is a risk that if we were to rely on merchant deployment of these technologies alone at this point in time, we may not see the rate and scale of new projects needed in the near-term to support decarbonisation of the power sector and meet the Net Zero commitment at low cost.’<sup>175</sup>

In other words, the pace of decarbonisation was the driving factor in readmitting solar and onshore wind to the CfD auction, cutting off purely market-based decision-making at the knees. Fast forward a few years, and this effect has been magnified by the Government’s reckless sprint to 2030.

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172 ‘UK Power Market Outlook 2024: U-Shaped Prices’, *BloombergNEF*, November 2024. [Link](#)

173 S. George, ‘Report: UK must build energy storage to tackle renewables cannibalisation risk’, *Edie*, December 2025. [Link](#). W. Blyth, R. Gross, P. Heptonstall, C. MacIver & M. Jamieson, ‘Zonal Pricing, Volume Risk and the 2030 Clean Power Target’, *UK Energy Research Centre*, March 2025. [Link](#)

174 ‘Clark: ‘No change on onshore wind CfDs’, *reNews*, February 2019. [Link](#). See also ‘Subsidy free solar comes to the UK: The UK’s first subsidy-free solar farm will be officially opened today (Tuesday 26 September) by Climate Change Minister Claire Perry’, *Department for Business, Energy & Industrial Strategy*, September 2017. [Link](#)

175 ‘Contracts for difference for low carbon electricity generation: consultation on proposed amendments to the scheme’, *Department for Business, Energy and Industrial Strategy*, March 2020. [Link](#)



Now, some people will argue at this point that CfDs are in fact a subsidy, not a price stabilisation mechanism. After all, for all the talk of CfDs paying consumers back, this has only happened once, during the price crisis caused by Russia's invasion of Ukraine.<sup>176</sup> Isn't the fact that CfDs are still necessary today evidence that renewables still aren't price-competitive?

Well, there are two answers to this. The first is – as Ed Miliband does – to argue on price. Prices in AR6 were pretty close to where wholesale prices are now and projected to be, though AR7 has seen 10% rises for offshore wind. But further, at the time of the price crisis when CfDs paid consumers back, only the more expensive early CfD contracts were online – the time lag involved in these projects means the cheaper contracts from AR3 and AR4 have only started generating in the last two years.<sup>177</sup>

Of course renewables do have wider cost impacts beyond these headline figures, as discussed extensively above. But for the purposes of this paper, the more important rebuttal is that – as we will see in Chapter 5 – significant amounts of renewables are being built subsidy-free, right now in Britain.

**‘ Once subsidies are put in place, they can be difficult to remove. Industry gets used to them, while lobbyists spring up to defend them ’**

So why don't the renewables developers answer their critics by letting them compete on their own – letting the market sort out what generation capacity to build?

The answer points to the final reason that CfDs have stuck around for so long – the age-old adage that once subsidies are put in place, they can be quite difficult to remove. Industry gets used to them, while lobbyists spring up to defend them. And why wouldn't they? CfDs are substantially easier contracts to sign than those in the private sector – particularly given the leverage that Clean Power 2030 gives to the developers.

Yet if we are ever to wean renewables off of CfDs, the time to start having that conversation is now. Because as we will show, the longer-term route to cheap power lies in the private sector, not an endless series of government handouts.

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<sup>176</sup> 'CfD Historical Data Dashboard', *Low Carbon Contracts Company*, 2024. [Link](#)

<sup>177</sup> Ibid.



# Chapter 4: The Promise and Peril of Nuclear

In the last chapter, we outlined both the positives and negatives of renewables, in terms of both the technology and the funding models, and in particular the reliance on state subsidy.

Disillusionment with renewables, whether because of their intermittency or the attached subsidies, has led to something of a rehabilitation of nuclear power on both left and right – offering both the reliable baseload power and small land footprint that renewables cannot, while still providing the zero-carbon power that gas cannot achieve.

But before we get too excited, it is worth pausing for a moment. Just as policymakers rushed towards renewables, do they not risk making a similar mistake if they rush towards nuclear? Proponents of nuclear are right to extol its reliability and security, but they must also address the shortcomings that have plagued the industry for decades now: that is, severe cost overruns and lengthy delays. And if your concern is that renewables are dependent on subsidy, then you really ain't seen nothing yet.

**‘ Proponents of nuclear are right to extol its reliability and security, but they must also address the shortcomings that have plagued the industry for decades now ’**

Nuclear will no doubt play an important role in the UK's evolving energy mix and good policy should look to unlock its potential as much as possible. But until it can be built cheaply and on time, without the current nightmare of bloat and overregulation, it would be foolhardy to put all of our eggs in the nuclear basket.

Indeed, from the perspective of energy abundance, the question should not be nuclear or renewables (or CCUS, or any other technology), but how can we encourage all of the above? This chapter will unpack all of this and more.

## Nuclear – the strengths and weaknesses

In contrast to the chapter on renewables, we will deal with nuclear's advantages and disadvantages fairly quickly, as they are much better known.

Starting with the strengths, nuclear provides reliable baseload power that does not depend on the weather. Whereas renewables have issues with intermittency and storage, nuclear can provide reliable baseload power, with average capacity factors in the UK of 72%.<sup>178</sup> The European Pressurised Water (EPR) reactors currently under way at Hinkley Point C and now Sizewell C have expected capacity factors of 92%.<sup>179</sup>

<sup>178</sup> 'DUKES 2025 Chapter 5: Electricity', *Department for Energy Security and Net Zero*, 2025. [Link](#)

<sup>179</sup> 'Advanced Nuclear Power Reactors', *World Nuclear Association*, April 2021. [Link](#)



Nuclear power is also incredibly dense as a source of energy: a single uranium pellet, no larger than a pill, produces the same amount of energy as 17,000 cubic feet of natural gas.<sup>180</sup> Indeed, it would take a solar farm the size of the Isle of Wight to match Hinkley Point C's capacity.<sup>181</sup>

Due to this density, nuclear also has relatively low fuel costs. Within the OECD, the total fuel costs of a nuclear power plant are approximately 20-25% of those of a gas combined-cycle plant, with much greater price certainty due to the low volumes required.<sup>182</sup>

Nuclear can also have lower ancillary costs, in terms of new transmission cables (relative to offshore wind for example). Power plants can be built close to current infrastructure: all eight sites designated for new nuclear by the Government, including Hinkley Point C and Sizewell C, are next to operating or decommissioned nuclear plants.<sup>183</sup> The caveat here is that reactors usually require an abundant water supply, which has largely limited them to the UK's coasts.

**Supporters of nuclear energy point to France as an ideal model. Nuclear constitutes 66-70% of electricity generation, wholesale prices are lower than the EU average and it is energy independent**

Another strong selling point is the lifetime of new reactors. Large-scale wind and solar farms currently have lifespans of approximately 25-30 years, meaning that much of the capacity being installed today will need to be replaced in the 2050s.<sup>184</sup> Meanwhile, Hinkley Point C and Sizewell C are due to last 60 years, with likely life extensions to 80 years.

Supporters of nuclear energy point to France as an ideal model. Nuclear constitutes 70% of electricity generation, wholesale prices are lower than the EU average and it is energy independent – a result of a fleet programme constructed during the 1970s and 1980s in response to the oil crises of the era.<sup>185</sup>

New nuclear capacity is also a bonus for energy security. While the plants themselves make for large targets, the engineering behind them is redoubtable. Meanwhile, they provide secure domestic generating capacity, while uranium can be sourced from allies like Canada and Australia and is enriched in Cheshire before being processed into nuclear fuel in Lancashire.<sup>186</sup> A civil nuclear power programme can also maintain skills that are transferable to military applications – Trident being the most obvious example.

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180 T. Zenou & T. Munson, 'Harnessing the Power of the Atom', *The Henry Jackson Society*, February 2025. [Link](#)

181 Solar, for instance, requires 19 square metres per MWh – H. Ritchie, 'How does the land use of different electricity sources compare?', *Our World in Data*, June 2022. [Link](#). S. Dumitriu, M. Hill, 'A Policy Playbook For Cheaper Nuclear', *Britain Remade*, September 2025. [Link](#)

182 For instance, a 50% change in uranium prices only marginally affects fuel costs, whereas a 10% change in gas prices can affect the LCOE of a CCGT by 7%. 'Economics of Nuclear Power', *World Nuclear Association*, September 2023. [Link](#)

183 'National Policy Statement for Nuclear Power Generation (EN-6) – Volume I of II', *Department for Energy and Climate Change*, July 2011. [Link](#)

184 B. Jopson, 'The problem with Europe's ageing wind farms', *Financial Times*, February 2024. [Link](#)  
'Briefing | Fact Checker', *Solar Energy UK*, March 2022. [Link](#)

185 B. Johnson, 'PM speech at Sizewell: 1 September 2022', *Prime Minister's Office 10 Downing Street*, September 2022. [Link](#). 'Quarterly average wholesale prices for selected regions, 2018–2026', *International Energy Agency*, 2025. [Link](#)

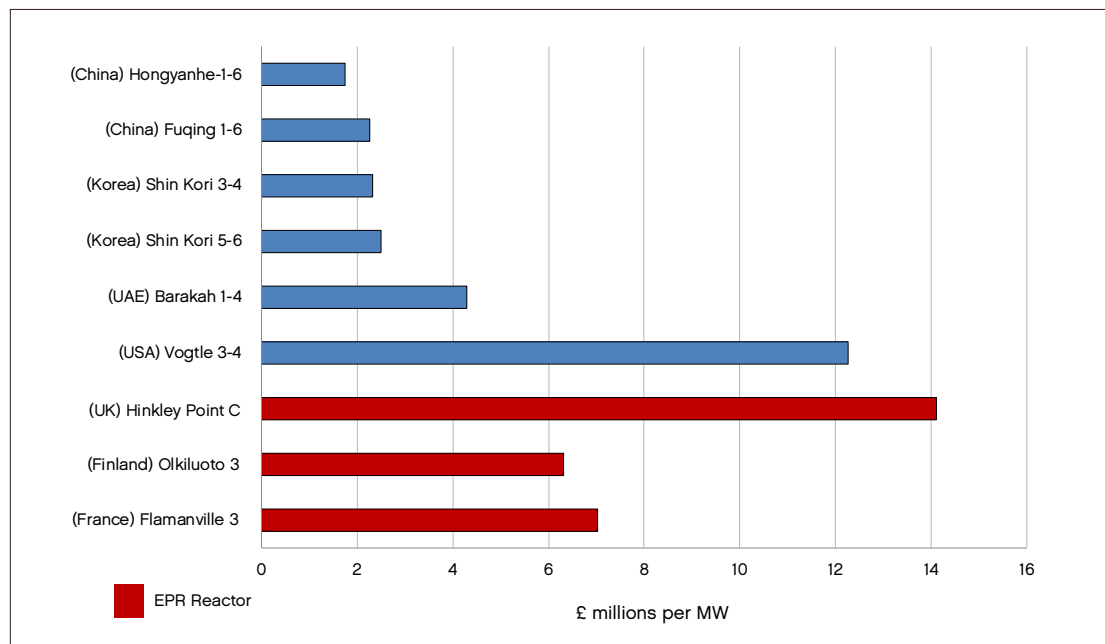
186 'World Uranium Mining Production', *World Nuclear Association*, May 2025. [Link](#). 'Springfields Fuels Limited', *Office for Nuclear Regulation*, July 2025. [Link](#)



The public are also much more positive towards nuclear than is often assumed. One recent poll showed that 49% of the public are supportive and 29% opposed, though only 22% of the public supported construction of a nuclear plant in their local area compared to 37% who were opposed.<sup>187</sup> Support for building wind and solar, even in the local area, is much more robust: a recent YouGov poll found 75% backing solar farms in their local area, and 66% onshore wind turbines, vs 32% who supported nuclear power (and even lower proportions who backed gas, shale or coal).<sup>188</sup>

Despite all of the above, however, nuclear power is not a panacea. For starters, the two new stations are not exactly ringing endorsements for the industry, beset as they are by severe costs overruns and delays. Hinkley Point was originally meant to start operations this year at a cost of £18bn (at 2015 prices). It is six years late and will now cost £46bn in nominal terms – equating to over £14 million per megawatt.<sup>189</sup>

### Costs of recent nuclear builds



Source: Dumitriu & Hill<sup>190</sup>

The British Government did – in a rare act of canny negotiation – ensure that the contractor, EDF, was solely responsible for cost overruns. But in return it signed a deal to buy Hinkley's output at an £89.50 strike price (at 2012 prices – now £130 in current prices).<sup>191</sup> That compares to average wholesale prices last year of £81.<sup>192</sup> Sizewell C will cost at minimum £38bn once completed – a huge uplift from the £20bn initially quoted.<sup>193</sup>

187 'Support for nuclear power', *YouGov*, 2025. [Link](#)

188 'How do Britons feel about expanding renewable energy?', *YouGov*, August 2024. [Link](#)

189 S. White, J. Pickard & R. Millard, 'UK nuclear plant hit by new multiyear delay and could cost up to £46bn', *Financial Times*, 2024. [Link](#). S. Dumitriu & B. Hopkinson, 'Infrastructure Costs: Nuclear Edition', *Notes on Growth*, December 2023. [Link](#)

190 S. Dumitriu & M. Hill, 'A policy playbook for cheaper nuclear', *Britain Remade*, September 2025. [Link](#)

191 'Hinkley Point C – Collection', *Department for Energy Security & Net Zero*, July 2018. [Link](#)

192 Note that baseload market reference prices for Winter 2025 is £85 and for Summer 2025 £84, as per the LCCC: 'Market Reference Prices', *Low Carbon Contracts Company*, 2025. [Link](#)

193 A. Armstrong & J. Pickard, 'Ministers set to admit Sizewell C Nuclear Plant Pricetag has soared to £38bn', *Financial Times*, 2025. [Link](#), NNB Generation Company (SZC) Limited, 'The Sizewell C Project – Funding Statement', *Planning Inspectorate*, May 2020. [Link](#)



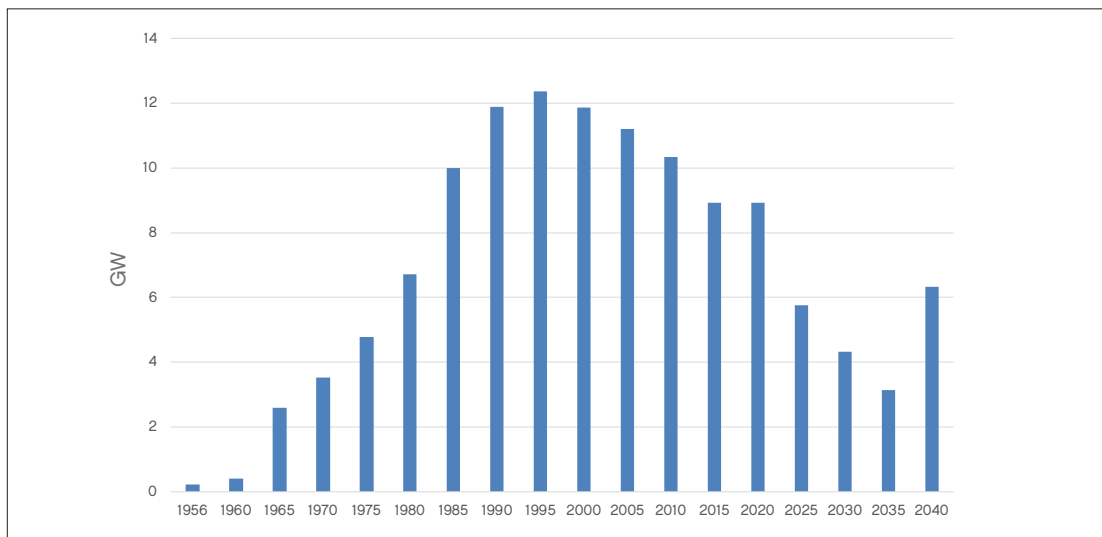
Of course, these extraordinary prices are not an unavoidable law of nature. In France, the Flamanville 3 reactor will cost approximately 50% less than Hinkley on a per megawatt basis, despite using the same EPR design. And the South Koreans are building reactors for a quarter of the price.<sup>194</sup> As John Fingleton’s review recently made clear, there is a thicket of overbearing regulations that plagues our nuclear industry.

However, that doesn’t negate the fact that in the here and now, Hinkley is decidedly not cheap, that Sizewell looks destined to share the same fate – and that future cost reductions for future nuclear projects are lamentably theoretical.

There is also a bigger issue here. Even if we could bring down the cost of construction, the scale of capital expense associated with gigawatt reactors is immense, as is the risk. It is no coincidence that two of the largest nuclear power operators in the world, EDF and KEPCO, are both state-owned.

Nuclear is also not a particularly near-term solution. Hinkley may not come online until 2031 and Sizewell C isn’t expected to operate until mid-to-late 2030s at the earliest. Small Modular Reactors (SMRs), which avoid many of the problems outlined here, are unlikely to be operating at scale until the mid-2030s and are not yet proven.<sup>195</sup> Furthermore, electricity demand is set to increase substantially over the next decade – but Hinkley and Sizewell will merely replace the capacity that is shutting down. From 28% in 1997, nuclear accounted for 14% of electricity generation in 2024, with all but one of our current reactors due to be shut by the end of the decade, despite extensions.<sup>196</sup>

#### UK nuclear capacity, 1956-2040



Source: DESNZ<sup>197</sup>

194 S. Dumitriu, ‘How red tape holds back nuclear power in Britain’, *Notes on Growth*, 2024. [Link](#)

195 A. Lawson & J. Jolly, ‘Planned UK nuclear reactors unlikely to help hit green target, say MPs’, *The Guardian*, February 2024. [Link](#)

196 Note the generation statistics are for the UK, not GB. T. Zenou & T. Munson, ‘Harnessing the Power of the Atom’, *The Henry Jackson Society*, February 2025. [Link](#). J. Kollwe, ‘EDF extends lifespan of two UK nuclear plants, securing 1,000 jobs for longer’, *The Guardian*, September 2025. [Link](#). J. Fingleton, ‘Nuclear Regulatory Review 2025’, *Nuclear Regulatory Taskforce*, November 2025. [Link](#). ‘Electricity fuel use, generation and supply (DUKES 5.6)’, *Department for Energy Security & Net Zero*, 2025. [Link](#)

197 This chart incorporates recent extensions to the Heysham 1 and Hartlepool sites (2028) as well as to both Heysham 2 and Torness (2030). It assumes HPC’s first reactor will come online in 2029 (though this could be delayed to 2031) and the second in 2030. We also assume that Sizewell C will be generating power by 2040. ‘Historical electricity data’, *Department for Energy Security & Net Zero*, 2025. [Link](#)



There are other disadvantages. Although nuclear power plants can achieve high capacity factors, their ability to provide baseload power is affected by their need for periodic refuelling, requiring planned shutdowns. Though some models can circumvent this limitation, the reactors at Hinkley and Sizewell will need to be shut down roughly every 18 months for a period of one month.<sup>198</sup>

And, as ever with nuclear power, there is the matter of nuclear waste. The UK's current stock is held at the Sellafield nuclear facility and with as yet unfinalised proposals for a Geological Disposal Facility, questions remain over the Government's long-term plan for waste storage, and the ultimate costs.<sup>199</sup>

**‘ It may seem odd that so much of Britain’s nuclear energy is going offline at the same time. It certainly speaks to a combination of inertia and poor planning ’**

## The Sizewell debacle

It may seem odd that so much of Britain's nuclear energy is going offline at the same time. And it certainly speaks to a combination of inertia and poor planning. Nick Clegg notoriously stated in 2010, when asked about the need for new nuclear, that: 'By the most optimistic scenarios from the government itself, there's no way they are going to have new nuclear come on stream until 2021, 2022. So it's just not even an answer.'<sup>200</sup> Indeed, since the construction of Sizewell B in 1995, no new nuclear power has been added to the grid.

That is now changing. But the key question is, and will remain, how to fund it?

Hinkley Point C, Britain's first new nuclear plant in a generation, utilised the CfD model. Under the deal, outlined above, the plant will receive an index-linked strike price of £92.50 in 2012 prices (now £89.50 with Sizewell's approval) for 35 years. Adjusted for inflation, that is now £130/MWh in 2025 prices – a far cry from current wholesale prices.

But of course, EDF will only get that money once Hinkley is up and running. After being forced to absorb the huge cost overruns – including an impairment charge of £11bn in 2023 – EDF was in no rush to repeat the experience for Hinkley's sister plant, Sizewell C.<sup>201</sup>

The Government therefore decided to offer up another existing model: the Regulated Asset Base (RAB), used in other infrastructure projects such as the Thames Tideway Tunnel and Heathrow Terminal 5.<sup>202</sup>

Under the RAB, there is no fixed strike price, and payments begin during the construction phase, rather than only when the asset is up and running. In return, what Sizewell is allowed to charge to consumers each year is based on a somewhat complex formula involving construction costs, an agreed rate of return, depreciation and other

198 'Commissioning and Operation of Hinkley Point C', *EDF Energy*, n.d. [Link](#)

199 'Why underground?', *Nuclear Waste Services*, January 2018. [Link](#)

200 D. Lawson, 'Our nuclear dithering is a national disaster', *The Sunday Times*, October 2024. [Link](#)

201 A. Lawson, 'EDF takes €12.9bn hit after Hinkley Point C delays and cost overruns', *The Guardian*, February 2024. [Link](#)

202 'The UK's nuclear regulated asset base (RAB) model and what it means for our energy customers', *Shell Energy*, July 2024. [Link](#)



factors, set off against revenues earned in the market (with a payback provision should revenues turn out higher).<sup>203</sup> And the contract lasts for 60 years against Hinkley's 35.<sup>204</sup>

Effectively, the RAB transfers the risk of cost overruns from investors to the public, paid for via surcharges on their energy bills. The quid pro quo is that the ability to charge consumers during the construction phase reduces the borrowing requirement – indeed, the whole structure is designed to reduce risk to investors.

This is not, by and of itself, a bad idea. In fact, it is a model the Centre for Policy Studies explored in a previous report.<sup>205</sup> It was also recommended by the National Audit Office and Public Accounts Committee in the aftermath of the Hinkley deal.<sup>206</sup>

**‘ When the full details of Sizewell C’s financing came out last summer, it became clear that things had not exactly worked out as intended ’**

The idea is that the RAB model lowers the capital cost of big infrastructure projects, given that investors have been substantially de-risked, while maintaining private sector discipline to ensure the project is delivered on budget. In 2021, the Government estimated that moving to a RAB model could save at least £30bn on each mega-project relative to a CfD structure.<sup>207</sup>

However, when the full details of Sizewell C’s financing came out last summer, it became clear that things had not exactly worked out as intended.

To start, true to form, the cost quoted was now £38bn in 2024 prices – a far cry from the previous official estimate of £20bn in 2020 (£25bn in 2024 prices).<sup>208</sup> The rate of return was guaranteed (plus a bonus) if costs end up between £38bn and £40bn. Between £40bn and £47.7bn, 50% of the costs will be borne by investors, while the other 50% will be added to consumer bills.<sup>209</sup>

Above £47.7bn, the Government – not private shareholders – is liable for the continued funding of the project, if it does not decide to cancel it altogether.<sup>210</sup> (All of these numbers are in real terms, so will rise further with future inflation.)<sup>211</sup> There is also a minor penalty for delay: if the project ends up two years behind schedule, the cost of capital will be cut by 0.5%, with a further 0.5% cut if it goes beyond four years.<sup>212</sup>

203 Davies et al., ‘New nuclear in the UK: publication of Sizewell C’s generation licence’, *Slaughter and May*, July 2025. [Link](#)

204 ‘Public information note on nuclear RAB and Sizewell C’, *Consumer Scotland*, March 2024. [Link](#)

205 E. Ives, ‘Bridging The Gap’, *Centre for Policy Studies*, January 2021. [Link](#)

206 A. Morse, ‘Hinkley Point C’, *National Audit Office*, June 2017. [Link](#). Committee of Public Accounts, ‘Hinkley Point C’, *House of Commons*, November 2017. [Link](#)

207 ‘Future funding for nuclear plants’, *Department for Business, Energy & Industrial Strategy (BEIS)*, October 2021. [Link](#). ‘Regulated Asset Base model for new nuclear (Impact Assessment)’, *Department for Business, Energy & Industrial Strategy (BEIS)*, October 2021. [Link](#)

208 R. Clun & M. Issimdar, July 2025. [Link](#)

209 ‘Investment in Sizewell C – Company announcement’, *Financial Times*, July 2025. [Link](#)

210 A. Armstrong & J. Pickard, ‘Ministers set to admit Sizewell C nuclear plant pricetag has soared to £38bn’, *Financial Times*, July 2025. [Link](#)

211 J.M. Davies, ‘Sizewell C will cost more than Hinkley: Is it worth it?’, *Energy Voice*, July 2025. [Link](#)

212 Davies et al., ‘New nuclear in the UK: publication of Sizewell C’s generation licence’, *Slaughter and May*, July 2025. [Link](#)



As a result, the project will in all likelihood be cheaper than Hinkley (and if not, then heaven help us). But total cost is not the same thing as cost to consumers.

Whereas at Hinkley, EDF and its Chinese partner bore the cost overruns, at Sizewell billpayers will be on the hook for a substantial portion. And given the project is structured as a RAB rather than a CfD, we don't yet know what the cost of the plant will be on a £/MWh basis.

But there is an even bigger sting in the tail. The whole point of the RAB model is to take risk away from private investors and put it onto consumers, thus lowering capital costs. Given such incentives, private money should be pouring in to lend to such a de-risked project with guaranteed returns. Indeed, Centrica, one of the equity investors, has stated that its internal rate of return will be 'more than 12%' assuming costs of £40bn, and 'above 10%' at the £47bn level.<sup>213</sup> (For context, the average return on the FTSE 100 over the last 20 years has been 6.3% on an annualised basis, or 3.5% accounting for inflation, while investors typically expect ~7% for infrastructure projects.)<sup>214</sup>

**Centrica, one of the equity investors, has stated that its internal rate of return will be 'more than 12%' assuming costs of £40bn, and 'above 10%' at the £47bn level**

Yet it turns out that of that vast construction cost, only a tiny fraction is actually coming from private investors. There is £3.25bn of equity from La Caisse, Centrica and INPP. Another £1bn is coming from EDF, now fully owned by the French state.<sup>215</sup> The UK state is putting in £3.8bn in equity directly, alongside £400m from the Nuclear Liabilities Fund, which manages decommissioning of the nuclear fleet.<sup>216</sup>

Most of the construction, however, is being funded not by equity but by debt. This includes £5bn in guarantees from France's export credit agencies for commercial bank loans and subsequent refinancing support.<sup>217</sup> But the vast majority – £36.6bn – is coming from Britain's new National Wealth Fund, which in turn is funded not by national wealth but public borrowing.<sup>218</sup>

In short, as it stands, only 6% of the capital is private.<sup>219</sup> The British state is putting in nearly all of the money, in exchange for an initial 44.9% stake.

This deal turns the logic of the RAB on its head. The whole point of transferring so much of the risk from investors to consumers is to lower capital costs and thus entice the private sector to fund the scheme. Indeed, when the RAB was first proposed as a model for new nuclear in 2018, the then Business Secretary set out

213 'Investment in Sizewell C – Company announcement', *Financial Times*, July 2025. [Link](#)

214 C. Archer, 'What are the average returns of the FTSE 100?', *IG*, May 2023. [Link](#). R. Millard & G. Plimmer, 'How Britain enticed investors to back its costly new nuclear plant', *Financial Times*, July 2025. [Link](#)

215 'The French State becomes the sole shareholder of EDF again', *EDF*, June 2023. [Link](#)

216 The £3.8bn presumably includes the £2.5bn of taxpayer funding previously announced. 'Further steps to prepare Sizewell C for construction', *Department for Energy Security & Net Zero*, January 2024. [Link](#)

217 'Press Release – Sfil: leading lender for the Export Credit Financing of the UK's Sizewell C Nuclear Power Plant, Showcasing the Excellence of France's Nuclear Industry', *Sfil*, November 2025. [Link](#). 'Bpifrance Assurance Export at the heart of the Sizewell C project', *Bpifrance*, November 2025. [Link](#)

218 R. Millard & G. Plimmer, 'How Britain enticed investors to back its costly new nuclear plant', *Financial Times*, July 2025. [Link](#)

219 Counting the Bpifrance guarantee (and subsequent Sfil refinancing) as public given the risk sits with the French government, despite the involvement of commercial banks



clearly that: ‘It remains the Government’s objective in the longer term that new nuclear projects like other energy infrastructure should be financed by the private sector, and so alongside our discussions with developers we will be reviewing the viability of a regulated asset base model as a sustainable funding model based on private finance for future projects.’<sup>220</sup>

With other recent RABs such as the Thames Tideway Tunnel and Heathrow Terminal 5, nearly all of the finance was private.<sup>221</sup> With the failed Hitachi bid to build a plant at Wylfa (abandoned in 2019), the Government was willing to consider taking a one-third equity stake in the project, and provide all of the debt financing – but in return for a CfD at no more than £75/MWh, and it was made clear that government financing was a one-off.<sup>222</sup>

**‘Equity holders still earn a healthy return up to a construction cost of £47.7bn, weakening the incentive for strenuous cost oversight’**

With a left-leaning hat on, one could perhaps make the argument that borrowing at sovereign rates will be cheaper than doing so in the private markets, and that by taking the largest equity stake, the taxpayer will receive a return on its investment. But raising £36bn in already stressed gilt markets strains the UK balance sheet still further.

Yes, the Government has committed to ‘recycling’ returns back to billpayers, at least to some extent.<sup>223</sup> But if cheap financing is the goal, why did the Government not choose to simply own the plant in full?

The original logic would likely have been to avoid cost blow-outs on the scale of HS2, by bringing in private sector discipline. But in the final structure, equity holders still earn a healthy return up to a construction cost of £47.7bn, weakening the incentive for strenuous cost oversight.

Of course, if the power produced from Sizewell ends up being substantially cheaper than that from Hinkley, it will be a powerful argument in this model’s favour. But lack of a fixed price from Sizewell means we won’t actually know what it will cost until it is generating – another downside of this model.

Both EDF and the Government loudly trumpet the cost savings that should come from building Sizewell as a near-replica of Hinkley.<sup>224</sup> Yet the financial structure of

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220 G. Clark, ‘Statement to Parliament on Horizon Project at Wylfa Newydd’, *Department for Business, Energy & Industrial Strategy (BEIS)*, June 2018. [Link](#)

221 Both projects did have a portion of their debt funded by the *European Investment Bank*, but the rest of the capital was private: ‘GBP 700m EIB backing for Thames Tideway Tunnel’, *European Investment Bank*, May 2016. [Link](#). ‘BAA Heathrow Terminal Five’, *European Investment Bank*, May 2002. [Link](#). A. Morse, ‘Review of the Thames Tideway Tunnel’, *National Audit Office*, February 2017. [Link](#). ‘Cost and Commercial Viability: Sources of Finance – Thames Tideway Tunnel’, *PricewaterhouseCoopers*, February 2018. [Link](#)

222 ‘UK unveils financial terms it offered Hitachi’, *World Nuclear News*, January 2019. [Link](#). ‘RAB model for nuclear: consultation’, *Department for Business, Energy & Industrial Strategy (BEIS)*, July 2019. [Link](#)

223 The Sizewell C VfM Assessment states ‘Recycling allows for a reimbursement amount, related to HMG’s debt and equity related returns, to lower supplier RAB levies. ‘Cost and Commercial Viability: Sources of Finance – Thames Tideway Tunnel’, *PricewaterhouseCoopers*, February 2018. [Link](#). ‘Sizewell C Final Investment Decision – Value for Money Assessment’, *Department for Energy Security & Net Zero*, July 2025. [Link](#)

224 R. Millard, ‘Sizewell C costs could hit £100bn including financing, modelling shows’, *Financial Times*, August 2025. [Link](#)



the project is not set up to deliver that. While sovereign borrowing does indeed bring cheap(er) debt, having the Government as the largest shareholder diminishes the benefits of private sector discipline. Not least because the private investors get generous returns for their rather minor contribution, even if the project goes substantially over budget.

Moreover, the allocation of risk between consumers and investors is utterly skewed. Unlike Hinkley, where EDF agreed to a fixed price and rightfully took on the risk of cost overruns, consumers are on the line to a large extent if the project goes over-budget. It is thus all the more remarkable that getting this deal over the line required the Government to provide nearly all of the financing, despite offering such generous returns to the private sector.

‘ On Sizewell, the allocation of risk between consumers and investors is utterly skewed ’

## The future of nuclear – small or large?

Thus far, we have discussed nuclear solely in terms of the mega-projects – because that is what is currently being built.

However, the Government recently announced that Wylfa, in Anglesey, North Wales, will be the site of Rolls-Royce’s new Small Modular Reactors.<sup>225</sup>

While undoubtedly a boon for Rolls-Royce, this development makes the future for large-scale nuclear more challenging. Wylfa was the best available site, which is why the previous Government was reportedly angling to announce a new project there before the election ended those plans.<sup>226</sup> The Government has announced that it is looking for alternative sites, and so we wait and see.<sup>227</sup>

We would argue that if we do build new large-scale nuclear, we need to ensure that it is no longer treated as a special case, deserving of quite enormous subsidy – and, in particular, that fixed-price contracts are used where possible, especially if the Government is taking a substantial debt or equity stake.

Far more promising, on the cost and subsidy front, are Small Modular Reactors (SMRs). These have been heralded as the future of the nuclear industry, as they have been designed to avoid many of the pitfalls that have so bedevilled their larger cousins.

Their fundamental characteristics are conveyed in the name: reactors that are smaller in size and capacity than current gigawatt-scale reactors (typically anywhere from 80 MW to 300 MW – though Rolls-Royce’s SMR is 470 MW) and assembled onsite using prefabricated components.<sup>228</sup> There are also yet smaller versions, called ‘micro-reactors’, of up to 20 MW.<sup>229</sup>

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225 ‘North Wales to pioneer UK’s first small modular reactors’, *Department for Energy Security & Net Zero*, November 2025. [Link](#)

226 A. Bowie, *Twitter/X*, September 2024. [Link](#)

227 ‘North Wales to pioneer UK’s first small modular reactors’, *Department for Energy Security & Net Zero*, November 2025. [Link](#)

228 ‘Rolls-Royce SMR homepage’, *Rolls-Royce SMR*, 2025. [Link](#)

229 ‘Microreactors’, *Idaho National Laboratory*, 2025. [Link](#)



These characteristics, combined with greater standardisation and economies of scale in production, are expected to avoid the extreme cost escalations and delays that currently plague nuclear construction. As Rolls-Royce puts it, an SMR is meant to be a 'repeatable, low-cost, factory product rather than [a] large one-off infrastructure project', as with Hinkley and Sizewell.<sup>230</sup> While some designs utilise novel technologies and fuels (so called Advanced Modular Reactors), the designs shortlisted for the Great British Nuclear SMR competition were all based upon existing reactor technology.

With reduced size and shorter timelines, SMRs should have lower up-front capital costs and thus be easier to finance (once deployed at commercial scale).<sup>231</sup> And while they could feed power to the grid as with their larger cousins, they could also be deployed to support industrial clusters and AI data centres. This wide array of deployment cases means these new reactors should be able to thrive without the need for government financial support or subsidy.

**‘ With reduced size and shorter timelines, SMRs should have lower up-front capital costs and thus be easier to finance once deployed at commercial scale ’**

That said, currently there are no operating SMRs in the West (though earlier this year GE Vernova received the green light to start construction on the first of four BWRX-300 units in Ontario, with operations expected to begin in 2030).<sup>232</sup> In the UK, the Government expects SMRs to connect to the grid 'in the mid-2030s'.<sup>233</sup> And it is worth noting that while the technology is for the most part proven (given these are based on existing reactor designs), the economics are not – at least not yet.

In short, SMRs are a promising technology. But we need to ensure that they do not become yet another graveyard for subsidy. A consultation on alternate routes to market was opened under the previous government and Labour announced in last year's Spending Review that is looking at pathways for private nuclear investment, resulting in the launch of the Advanced Nuclear Framework in February 2026.<sup>234</sup> Within it, the Government has stated its intent to provide limited, in-principle endorsement of viable nuclear projects to unlock and encourage private investment, offering post-construction CfD-style revenue support or risk protection for high impact, low probability (HILP) events, each to be reviewed on a case-by-case basis. Simultaneously, nuclear developers can approach the NWF to seek debt or equity investments outside of the direct government support mentioned above, during both the development and construction phases of a project.

This is clearly sensible – we should want to encourage as many designs and companies to set up shop in the UK as we can. And given none of these reactors are yet commercialised, the Government clearly has an interest in helping support the initial first-of-a-kind reactors whether with a CfD, NWF funding or other means.

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230 'Our approach', *Rolls-Royce SMR*, 2025. [Link](#)

231 Langengen et al, 'Revitalising nuclear: the UK can power AI and lead the clean energy', *Tony Blair Institute for Global Change*, December 2024. [Link](#)

232 Estimated costs for the fourth unit are put at CAD4.1bn (£2.2bn). A. Hunt, 'Canada's first SMR project: How is CAD20.9bn cost calculated?', *World Nuclear News*, May 2025. [Link](#)

233 'Rolls-Royce SMR selected to build small modular nuclear reactors', *Department for Energy Security & Net Zero*, June 2025. [Link](#)

234 'Alternative routes to market for new nuclear projects', *Department for Energy Security & Net Zero*, April 2024. [Link](#). 'Spending Review 2025', *HM Treasury*, June 2025. [Link](#). 'Advanced Nuclear Framework', *Department for Energy Security & Net Zero*, February 2026. [Link](#)



Indeed, a lack of support has already proven deleterious, with Newcleo announcing its withdrawal from the UK after it failed to receive backing for its lead-cooled fast reactors (though the Government's refusal to grant the company access to the UK's plutonium stockpile for recycling was also a factor).<sup>235</sup>

**‘ The Government's recent commitment of £2.5bn towards Rolls-Royce as the winner of its SMR competition is a welcome start ’**

Thus the Government's commitment in 2025 of £2.5bn towards Rolls-Royce as the winner of its SMR competition was a welcome start.<sup>236</sup> Selecting only one winner was a disappointment – but the market appears to be developing nevertheless. Centrica has announced a joint development agreement to look at deploying X-energy's 80 MW AMRs, which use novel nuclear technology, at Hartlepool. Holtec is looking to bring its SMR-300 to Cottam in Nottinghamshire (aimed at data centres), while TerraPower is evaluating potential sites for its AMR.<sup>237</sup>

For all of these projects (and any others), the Government should be rolling out the red carpet, via development support and CfDs for first-of-a-kind reactors. Britain Remade has suggested simply letting new reactor designs compete in the existing CfD auction round, which would be a neat way to ensure a predictable policy regime and value for public money.<sup>238</sup>

Ultimately, as with renewables, we need to create a situation where new nuclear does not mean billions of pounds in subsidies for every project that is built. Indeed, as we will see in the next chapter, there is every reason to think that once mature, SMRs should be able to deploy fully privately, overcoming the challenges that have bedevilled their larger cousins.

235 M. Oliver, 'Nuclear power start-up pulls out of Britain as Miliband drags feet', *Telegraph*, July 2025. [Link](#)

236 S. Dumitriu, '15 thoughts on what the Spending Review means for British Nuclear', *Notes on Growth*, June 2025. [Link](#)

237 'UK PM's Office Announces the Joint Plan by Holtec International and EDF UK to Provide SMR-300s to Power Data Centers at the Cottam site in the Midlands', *Holtec International*, September 2025. [Link](#).  
'TerraPower and KBR Collaborate to Bring Natrium® Advanced Nuclear Power Plant to the UK', *TerraPower*, September 2025. [Link](#)

238 S. Dumitriu & M. Hill, 'A policy playbook for cheaper nuclear', *Britain Remade*, September 2025. [Link](#)



# Chapter 5: The Market Strikes Back

## Introduction

The previous two chapters explored renewables and nuclear respectively, as the two most prominent sources of the new generation that are in the pipeline.

While they have many differences, one thing they broadly share – at least as currently deployed – is a dependence on subsidies. Solar and wind have been driven forward by the CfD, while the new nuclear power stations at Hinkley Point C and Sizewell C have been underpinned by the CfD and RAB, respectively. Can we ever move away from our dependence on government support to build new generating capacity?

Happily, the answer is a resounding yes. Not only is such a thing possible, in fact there is already a strong private market for new power supply, requiring no government subsidy.<sup>239</sup> It is being driven by businesses up and down the country seeking to hedge their power costs and save money while cutting carbon, while giving developers the certainty they need to finance new generation. And while it has grown to significant scale in recent years (for example supporting some of the largest solar farms in the country), most of Westminster seems blissfully unaware of its existence. This model is a corporate Power Purchase Agreement (PPA).

**‘ Can we ever move away from our dependence on government support to build new generating capacity? Happily, the answer is a resounding yes ’**

At its core, the PPA is analogous to the CfD, guaranteeing a power generator a fixed price for their power, usually for 10-15 years. Contracts are bilaterally negotiated between buyer and seller, with a host of different arrangements on offer. Put simply, this is about people (or rather companies) making decisions about what energy supply is best for them, rather than Government doing so on their behalf.

The European PPA market has seen impressive growth, more than doubling between 2020 and 2025, albeit down from a record year in 2023.<sup>240</sup> Britain has the fifth largest market in Europe in 2025 – impressive, but far behind leaders such as Spain, who

239 Though it's worth acknowledging that even with a PPA there will still be elements of socialised cost, such as grid infrastructure, the Capacity Market, system actions in Balancing Mechanism, etc.

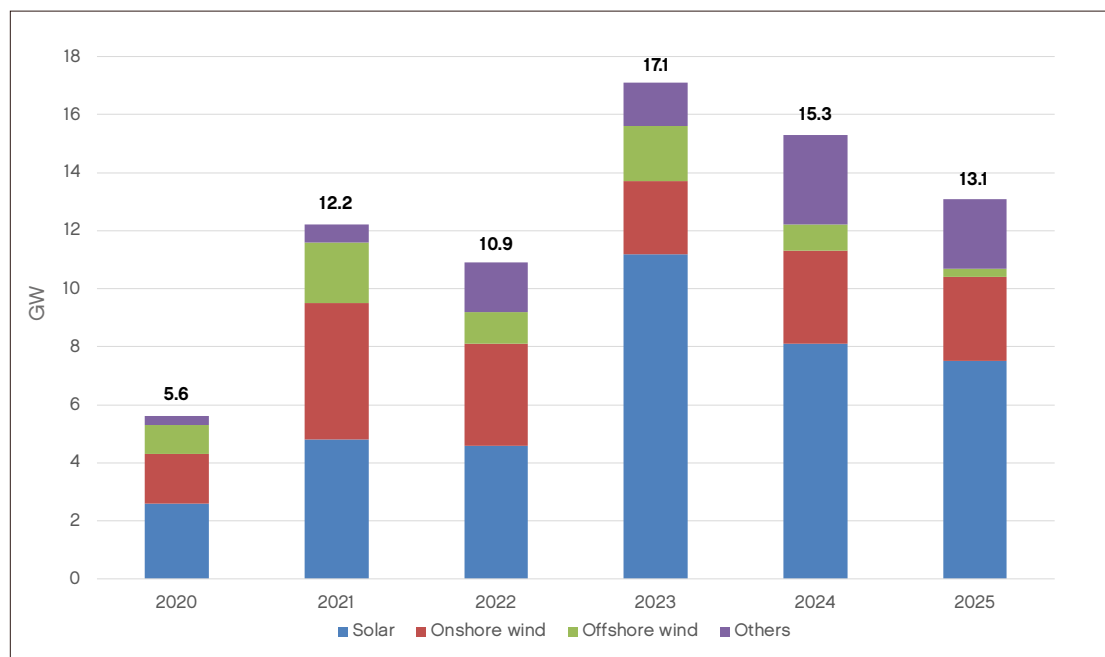
240 'N. Briet, D. Hirschier & A. Valassas, 'Renewables Market Outlook 2026', *Pexapark*, 2026. [Link](#) Page 22. Note that while this report prefers to use Pexapark data as explained below, the relevant 2025 figures are not yet available, and RE-Source at least provides an indication of the overall trend even if the individual transactions have not been screened to the same degree. This trend has been confirmed with industry figures. 'PPA Deal Tracker: PPA Announcements', *RE-Source*, 2026. [Link](#)



have pressed ahead with the private model.<sup>241</sup> Indeed, most new solar generation there has been built not with subsidies but with PPAs.<sup>242</sup>

In Great Britain, PPAs have started to support ever-larger generation projects. The largest operating solar farm in the country (as of July 2025), the 373 MW Cleve Hill project in Kent, is covered by a PPA from Tesco for two thirds of its output, with the other third backed by a CfD.<sup>243</sup> The second largest, the 75 MW Llanwern solar farm in Wales, is backed entirely by a PPA signed with Anglian Water, with no CfD at all.<sup>244</sup>

### European PPA market volume, 2020-2025



Source: Pexapark<sup>245</sup>

PPAs have also driven new deployment for wind projects, albeit at a smaller scale. And while nuclear is at a more nascent stage, first-of-a-kind SMR deployment to support the growth of data centres in the US has been underpinned by PPAs, as has a deal to restart the notorious Three Mile Island. Here in Britain, PPAs are helping deploy micro-reactors, while there is a project in the works to deploy SMRs based on PPAs in Teesside.

<sup>241</sup> Note that as explained further in this chapter, the term PPA can have a variety of meanings. This statistic is from data provider Pexapark, whose primary criterion for inclusion is bearing price risk, and thus excludes e.g. Route-to-Market PPAs for CfD assets. That said, they include PPAs for existing assets with tenors of five years or longer, so the data will not all be new-build assets. However Pexapark data shows that in 2025 new-build assets represented c. 80% of the European solar PPA market, and c. 90% in 2024, and Pexapark attributes at least some of this trend to assets securing long-term offtake after their commercial start date, and thus not being initially counted as new-build. N. Briet, D. Hischer & A. Valassas, 'Renewables Market Outlook 2026', Pexapark, 2026. [Link](#), Page 23

<sup>242</sup> Note while the Spanish government did introduce a renewable auction scheme (REER) in addition to the ongoing PPA and merchant deployment, very few of the winning bidders actually opted to take up these contracts, instead selling their power via PPAs or merchant routes, or withdrawing the projects. 'National Survey Report of PV Power Applications in SPAIN', International Energy Agency – Photovoltaic Power Systems Programme, 2023 version [Link](#) Page 14 and 2022 version [Link](#). C. Monforte, 'Las adjudicatarias de las subastas de renovables celebradas desde 2021 renuncian a la retribución (The companies awarded renewable energy contracts in auctions held since 2021 are waiving their remuneration)' *El País*, March 2025. [Link](#) (Translated via Google Translate).

<sup>243</sup> 'Tesco Agrees Largest UK Corporate PPA for Solar Power in Landmark Infrastructure Project', *Tesco PLC*, October 2024. [Link](#). M. Green, 'Quinbrook secures offtake agreements with Tesco and Shell for 363 MW Cleve Hill Solar Park', *Solar Power Portal*, October 2024. [Link](#)

<sup>244</sup> J. Jackman, 'The 7 Largest Solar Farms in the UK', *Sunsave*, April 2025. [Link](#). 'UK's Largest Operating Solar Farm Secures 20-Year Sleeved PPA', *NextEnergy Capital*, October 2024. [Link](#)

<sup>245</sup> N. Briet, D. Hischer & A. Valassas, 'Renewables Market Outlook 2026', Pexapark, 2026. [Link](#)



PPAs certainly do have their challenges, and in today's market are clearly second fiddle to the CfD and RAB. Indeed for a sense of scale, the GB PPA market supported c. 1 GW of new capacity in both 2024 and 2023, relative to c. 9.6 GW and c. 4 GW awarded in the 2024 and 2023 CfD auctions respectively.<sup>246</sup> So while ripping away subsidies overnight wouldn't be a viable option, we can and should focus on scaling up PPAs while weaning generators off the support models over time. This chapter (and Chapter 7) will examine each of these issues in turn.

↳ **Physical PPAs are more common in Britain, though the virtual model is gaining steam (and generators tend to be indifferent between the two)** ↵

## How do PPAs work?

To understand what's driving the PPA market, it's helpful to understand the agreements themselves in a bit more detail. Firstly, it is worth clarifying that the term PPA can cover a variety of commercial arrangements – but in this paper, we mean it as a long-term contract which enables a developer to build a new generating station, as an alternative to a subsidy scheme, where the buyer is assuming the price risk.<sup>247</sup>

Broadly, there are three types of such PPAs. The first is on-site or 'direct wire', whereby a business installs for example solar panels on its roof or on land nearby, with a cable connecting directly to its facility (these tend to be on the smaller side).

Larger generating stations tend to be off-site, and either contract a 'physical' arrangement with the offtaker, or a 'virtual' one. In a physical arrangement, the power generated by the wind farm or SMR would be remotely allocated to the corporate ('sleeved in' to its power supply), utilising the services of an energy supplier or trader to transform the intermittent renewable power into a shape matching the corporate's consumption at its various sites. In a virtual arrangement, the offtaker and generator buy and sell their physical power in the usual way (i.e. independently of each other), and then settle the fixed-price virtual PPA in a separate transaction. Physical PPAs are more common in Britain, though the virtual model is gaining steam (and generators tend to be indifferent between the two).<sup>248</sup>

On the buyer's side, procuring a PPA is quite different from purchasing a traditional business energy contract. Whereas the latter can be fixed price only for a period of months to a few years, a PPA can last anywhere from five to 20 years (though a recent deal was 40 years long).<sup>249</sup> And a PPA requires far more 'engagement' on the part of the procurement team to understand the nuances and risks of the contract.

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246 Ibid. For AR6 excludes offshore wind permitted reduction as this was not 'new' capacity. Regarding the PPA statistics, 2024 is confirmed to be all 'new' capacity ([here](#)), and per email correspondence with Pexapark, 2023 is also confirmed to be all new capacity save for one operational deal of 35 MW. 'Energy UK Explains: Allocation Round 6', *Energy UK*, September 2024. [Link](#). 'CfD Allocation Round 5 Results – a briefing', *Low Carbon Contracts Company*, September 2023. [Link](#)

247 For example, renewables with CfDs often utilise a 'Route-to-Market PPA' to physically sell their power in the wholesale market – but of course the price risk is assumed by the Government (and consumers), not by the PPA counterparty. In future this definition could expand to include 'repowered' assets reaching the end of their operational life (which need significant refurbishment to continue operating).

248 'Power Purchase Agreements: An overview', *The Strategic Investment Board*, September 2020. [Link](#)

249 A. Rolt, 'Welsh Water inks PPA with renewables developer Innova', *BusinessGreen*, February 2025. [Link](#)



That's because most PPAs are sold as what's known as 'Pay-as-produced' (mirroring the structure of a CfD), whereby a buyer commits to take all (or a defined percentage) of the generation of a new solar farm (for example) at a fixed price. For renewable assets, the corporate buyers also need to contend with the intermittency of generation, and thus will also need to procure 'balancing' and 'shaping' services to firm up this generation, in return for a 'sleeving' fee.<sup>250</sup> And here the production profile of the underlying asset matters a fair bit – solar only generates during the day and far more in summer than winter, whereas wind is typically winter-weighted though more variable.<sup>251</sup> So buyers will want to choose an asset (or combination of wind and solar assets, including batteries) which matches their underlying demand in order to minimise these costs.

Indeed, it's worth highlighting the role batteries can play. Britain had by far the largest market for batteries in Europe in 2025 (given the ability to earn revenues across multiple markets including wholesale trading, system balancing and frequency response, and capacity market payments).<sup>252</sup> Though most batteries in Britain which are co-located with generation operate independently from each other, so-called 'hybrid' PPAs are starting to emerge in Europe.<sup>253</sup> These can help manage shape risk by storing electricity when renewable generation is high and prices are low, and releasing it later when demand and prices are higher. This is particularly relevant for solar PPAs, where in the summer months peak output can be higher than a corporate's demand, driving higher shaping costs. By pairing PPAs with battery storage, either through co-location or contractual arrangements, buyers can lower the cost of converting variable renewable output into a more usable supply profile. These types of arrangements will likely be increasingly important as the penetration of renewables increases.

**‘A typical business energy contract lasts at most for up to five years. But many corporates want the certainty that fixing prices for longer brings, particularly users with larger energy needs’**

## What's driving the PPA market today

Why are so many corporations opting to take on all this complication? While the answer will vary from business to business, the two main drivers are cold, hard economics, and the carbon benefits (and often both).

Starting with the former, the key benefit for businesses is the ability to hedge all or a portion of their power costs over a longer time horizon.

A typical business energy contract lasts at most for up to five years.<sup>254</sup> But many corporates want the certainty that fixing prices for longer brings, particularly users with larger energy needs. This trend accelerated substantially in the energy price crisis of 2021-2022, where skyrocketing prices in the wholesale market forced many

250 Balancing manages the difference between forecast and actual generation, while shaping converts the 'as-produced' power into a baseload block, usually on a monthly or seasonal basis. 'What is Power Balancing and Shaping and How Does it Work?', *EDF Energy*, April 2024. [Link](#)

251 C. Bowden, '13 Power Purchase Agreement Terms Explained', *Squeaky Energy*, August 2023. [Link](#)

252 Z. Jennings, 'ME BESS GB: Revenues fall to £59k/MW/year in November 2025', *Modo Energy*, November 2025. [Link](#)

253 N. Briet, D. Hischer & A. Valassas, 'Renewables Market Outlook 2026', *Pexapark*, 2026. [Link](#)

254 'Set up a business energy contract', *Ofgem*, 2025. [Link](#)



businesses to seek alternatives for their power supply. Some found that they could make a substantial near-term saving on their power bill by signing PPAs.

More recently, prices have subsided. But a number of companies have still found value in stabilising a portion of their power prices over a longer time horizon. In the conversations with corporates undertaken as part of this research, many said that the main benefit of a PPA was the ability to hedge and plan over the long term, while reducing exposure to price spikes and potentially beating the market. Similarly, when we asked one of the advisory firms which help corporates navigate the PPA process for their 'elevator pitch', the key point was price certainty, not carbon. (Though a PPA only stabilises wholesale costs, not charges and levies, which will become an increasingly important part of the overall bill going forward.)

Prices for PPAs have generally been competitive, both relative to those coming out of the CfD and relative to current wholesale prices. EY have shared pricing data with the CPS based on recent tender processes, suitably aggregated and anonymised. Their estimates, summarised in the table below, show that the bulk of 15-year solar PPAs are pricing in the low £60s to low £70s/MWh, which is competitive with the AR7 clearing price of £68/MWh.<sup>255</sup> Similarly, the bulk of 15-year onshore wind PPAs are coming in at the mid £60s to mid £70s/MWh, around the price of the AR7 CfD auction of £76/MWh.<sup>256</sup>

However, far more important from the customer's perspective is that these prices represent savings compared to the wholesale market, where the average price in 2025 was £81/MWh (though sleeving fees add a bit on top, as explained below.)<sup>257</sup> Indeed, from conversations with market participants we understand that it's pretty rare to see a deal signed that is 'out of the money' in expected NPV terms over the life of the contract. (Though of course whether the contract will stay 'in the money' over its lifetime depends on how wholesale prices evolve, and anticipated future declines may make corporates more reluctant to sign deals.)

#### Expected virtual PPA prices based on recent tender EY processes<sup>258</sup>

	10-year	15-year
Solar	Mid £60s to mid £70s/MWh	Low £60s to low £70s/MWh
Onshore wind	High £60s to high £70s/MWh	Mid £60s to mid £70s/MWh

Source: EY

It's worth noting that the economics can look different for businesses installing rooftop solar, should they choose to purchase the panels outright rather than utilise a PPA model. In the latter case the upfront costs are obviously high, but any power generated

255 J.P. Casey & K.M. Ross, 'Solar PPA Prices Stable After Extended European Decline', *Solar Power Portal*, October 2024. [Link](#). In December 2025 prices, according to Bank of England inflation data: 'New Auction delivers unprecedented clean, homegrown power', *Department for Energy Security & Net Zero*, February 2026. [Link](#)

256 'UK PPA market doubles, with new onshore wind projects in England competitive with CfD', *Veyt*, May 2025. [Link](#). In December 2025 prices, according to Bank of England inflation data: 'New Auction delivers unprecedented clean, homegrown power', *Department for Energy Security & Net Zero*, February 2026. [Link](#)

257 Referring to day-ahead wholesale prices, averaged across 2025. 'IMRP actuals', *Low Carbon Contracts Company*, 2025. [Link](#)

258 Provided by EY directly, based on bids from developers as part of 'request for proposal' tender processes. Note: For a virtual PPA, pay-as-produced, with CPI indexation, inc. REGOs, for 2026/2027 start. These are only approximate ranges from most signed PPAs during 2024 and 2025. There are still some developers who bid higher than this, and more recently a few who are now able to bid lower than these ranges.



from the panels is ‘free’ rather than at a fixed price and avoids green levies, while also coming with tax benefits.<sup>259</sup>

For physical PPAs, corporate buyers will need to pay for shaping and balancing costs on top of the above price. EY has again provided the below approximate figures based on recent processes they have run – and corporates must factor in these additions if comparing to just buying power on the market. And it’s worth noting that while buyers of virtual PPAs don’t pay these fees directly (as vPPAs are purely financial transactions with no physical delivery of electricity), the corporate is indirectly exposed to shaping costs as pay-as-produced vPPAs settle on a volume weighted average price. This means that when there is a lot of solar power on the market and prices are depressed, the corporate has to pay more to settle up to the vPPA price.

**Typical sleeving fees for physical PPAs<sup>260</sup>**

	Solar Physical PPA	Wind Physical PPA
Shaping costs*	£6-12/MWh	£5-12/MWh
Balancing costs	£2-3.5/MWh	~£7-10/MWh
Management fees	£0.2/MWh	£0.2/MWh

\* Largely depends on buyer demand profile

Source: EY

However, as mentioned above, there is a second factor beyond pure economics that is driving the PPA market. The fact that PPAs are dominated by renewables reflects corporations’ desire to reduce carbon and affirm their eco-friendly credentials.<sup>261</sup> In particular, signing a PPA for wind and/or solar enables firms to demonstrate that their commitment to ‘green’ electricity is driving real-world emissions reductions (via new-build generation), which is much harder to demonstrate when going via the energy firms.<sup>262</sup>

Tesco, for example, is part of the RE100 initiative alongside other household names such as Unilever, Diageo, and Lloyds, which means that it has committed to sourcing 100% renewable electricity.<sup>263</sup> Many other companies have similar initiatives: Multiplex, the cinema operator, signed a PPA as part of its pledge for net zero onsite emissions by 2025.<sup>264</sup> Large tech firms are also big players in the PPA space – Microsoft recently signed a framework PPA agreement with Brookfield to deliver a staggering 10.5 GW of renewable capacity across the US and Europe, to help deliver its decarbonisation ambitions.<sup>265</sup>

259 ‘D. Lewis, ‘The Expert Guide to Commercial Solar ROI & Payback in the UK’, *Infinity Energy Services*, January 2026. [Link](#) ‘Why “Net Zero” Became Politically Toxic — And Why Onsite Renewables Are the Practical Way Through’, *OnGen*, October 2025. [Link](#)

260 Ibid. Shaping costs largely depend on buyer demand profile

261 Though this may evolve as the grid gets greener over the next few years, and thus the incremental emissions impact from new renewable projects decreases

262 ‘Renewable Energy Certificates Explained’, *Good Energy*, May 2021. [Link](#)

263 ‘RE100 Members’, *RE100*, 2025. [Link](#)

264 ‘Multiplex Accelerates Net Zero Goals with Ampyr Solar Europe Partnership on a Solar Power Station in Norfolk’, *Multiplex*, November 2023. [Link](#). G. Heynes, ‘Ampyr Solar Europe Signs PPA with Multiplex’, *Solar Power Portal*, November 2023. [Link](#)

265 ‘Brookfield and Microsoft Collaborating to Deliver Over 10.5 GW of New Renewable Power Capacity Globally’, *Brookfield*, May 2024. [Link](#)



In the US, the large tech companies are also using PPAs to kickstart the nuclear revolution, helping to deliver stable decarbonised power to drive forward AI. Google has recently signed a deal with Kairos Power to help bring the company's first SMR online by 2030, with subsequent deployments totalling 500 MW through 2035.<sup>266</sup> Microsoft agreed a 20-year PPA to restart the 835 MW Three Mile Island (Unit 1) to power its own data centres.<sup>267</sup>

Overall, demand from corporates for green energy is certainly driving a lot of the PPA market – but so too is the ability to hedge electricity prices, providing stability, the ability to plan over a longer time horizon, and cost savings to varying degrees.

## Barriers to PPAs scaling up further

While PPAs have been growing strongly in the UK (and around the world), there are a number of barriers to the market scaling up further, both on the demand side and the supply side. Indeed, for both renewables and nuclear, private business models are a complement to their much larger state-backed equivalent, and not (yet) ready to take all of the heavy lifting. What's preventing them from doing so?

On the demand side, the biggest barrier is that the current 'universe' of buyers is inherently limited. The most natural buyers of PPAs, aside from the big tech firms, would be large companies, with substantial and sustained electricity needs – who also tend to be the most sophisticated electricity purchasers. It's therefore no surprise that Germany is one of the leaders in the European PPA market.<sup>268</sup> By contrast, in Britain our heavy industry has been seeping away over decades – and thus here the main buyers have been IT, telecom and retail companies. That said, as power-hungry data centres come online, there will be a new source of large-scale demand. Ditto for the newly electrified industries (what's left of them) such as steel.

**‘ In Britain our heavy industry has been seeping away over decades – and thus here the main buyers have been IT, telecom and retail companies ’**

In the wider economy, those with more modest electricity needs tend not to be as sophisticated as larger buyers in terms of their familiarity with the power markets or willingness to negotiate a complex contract. Relative to a standard business electricity contract, PPAs are a relatively novel concept – indeed, in our conversations with market participants, many have stressed that the 'education' piece is a crucial one. Due to the complexity of PPAs, and size of viable generation projects, there is a natural minimum offsite PPA size, around 20GWh/yr, below which there aren't sufficient economies of scale to justify the transaction costs.<sup>269</sup>

Even for sophisticated customers, hedging electricity prices over the longer term may not make sense for all businesses. Indeed, some will only want to hedge out a

266 M. Terrell, 'Google-Kairos Power nuclear energy agreement', *Google*, October 2024. [Link](#)

267 'Constellation to Launch Crane Clean Energy Center Restoring Jobs and Carbon-Free Power to The Grid', *Constellation Energy*, 2024. [Link](#). 'Constellation to restart Three Mile Island unit powering Microsoft', *World Nuclear News*, September 2024. [Link](#)

268 'European PPA Market Surges: 19 GW Contracted in 2024', *Rinnovabili*, April 2025. [Link](#)

269 Conversations with EY



portion of their demand, to be able to react to market developments – particularly if their ability to pass through costs to customers is limited.

Finally, domestic customers of course make up a substantial portion of demand, who obviously cannot contract with a generator on their own. Of course, that limitation does not apply to the big domestic suppliers – and later in this report, we will address the huge potential for PPAs in the retail market. But at least for the moment, the universe of buyers for PPAs is inherently limited.

These are not the only factors. Another barrier to mention is credit (or counterparty) risk – essentially the risk that the buyer of the power (though sometimes also the generator) goes bust, voiding the contract. Whereas CfD or RAB contracts are backed by Government and thus the risk is essentially nil (though Reform UK may beg to differ), smaller or less-established companies are typically not as creditworthy. They can often struggle to agree a long-term PPA, at least at an attractive price or without substantial collateral or credit insurance, leaving the market for the most part to only those with a high (investment-grade) credit rating.<sup>270</sup>

Another hurdle to overcome has to do with project scale. Ever-larger renewable projects mean ever-larger volumes of power to sell, and finding a buyer capable of taking all that power can be a challenge. PPAs have therefore tended to support small or medium-sized assets. However, this is starting to change – the Anglian Water deal was for a 75 MW asset, while the Tesco deal set a new solar record at the equivalent of ~250 MW.<sup>271</sup> Amazon recently made headlines in buying 476 MW of wind and solar capacity in Spain and Portugal across several PPA agreements.<sup>272</sup>

**‘ Ever-larger renewable projects mean ever-larger volumes of power to sell, and finding a buyer capable of taking all that power can be a challenge ’**

Indeed, even offshore wind, traditionally thought of as a no-go zone for corporate PPAs due to the immense scale of the projects, is now seeing real PPA activity. The 882 MW Moray West offshore wind farm is the first in the UK to rely on corporate customers for the majority of its output, with Amazon taking 473 MW and Google taking 100 MW alongside a CfD for 294 MW.<sup>273</sup> Admittedly, this still does involve a CfD. And newer projects can go up to several GW in scale, which would be very difficult to sell to a single offtaker.

That said, ‘multi-buyer’ PPAs are starting to crop up. Last year, five local energy co-operatives signed a 10-year PPA agreement to take a small portion of the output of the 630 MW London Array offshore wind farm (previously developed via the Renewables Obligation scheme, and so not ‘new’ capacity).<sup>274</sup> That said, negotiating a PPA with several offtakers obviously adds to the overall complexity and costs of the transaction, even if they are all party to one agreement rather than signing separate contracts.

270 ‘Review of Electricity Market Arrangements: Summary of responses to second consultation’, *Department for Energy Security & Net Zero*, December 2024. [Link](#)

271 I.e. ⅔ of the project

272 S. Stone, ‘Amazon inks offtake deals for further 476 MW of clean power from Iberdrola’, *BusinessGreen*, February 2026. [Link](#)

273 ‘Amazon Signs Agreement with ENGIE to Procure 473 MW of Renewable Energy from the Moray West Offshore Wind Farm in Scotland’, *ENGIE*, January 2024. [Link](#). A. Buljan, ‘Moray West: First UK Round 4 Offshore Wind Project to Reach Financial Close’, *OffshoreWind.biz*, April 2023. [Link](#). ‘ENGIE and Google Conclude a Corporate PPA Relying on Ocean Winds Offshore Wind Development’, *ENGIE*, November 2022. [Link](#)

274 ‘RWE Signs PPA with 5 UK Co-operatives’, *RWE*, April 2025. [Link](#)



In the public sector, the Crown Commercial Service helps aggregate various public-sector buyers for the purposes of procuring PPAs (and recently launched a new Framework Agreement with this aim).<sup>275</sup> In the private sector no such aggregation function exists, though a whole industry of advisors and online marketplaces has cropped up to help smooth transactions, while energy suppliers themselves can often help match supply with demand.<sup>276</sup>

Finally, there is often an inherent maturity mismatch between how long a buyer will want to fix their power prices and how long a seller needs to get cheap financing. While some businesses do want to hedge their prices for 15+ years (a recent deal with Welsh Water was for 40 years), most corporates would ideally want a contract of five to 10 years. A renewable asset would ideally want 10-15, however.<sup>277</sup> A CfD historically offered a guaranteed 15-year contract, which the Government has just extended to 20 years on the urging of the renewables lobby.<sup>278</sup>

This hints at a final barrier to scaling PPAs – the CfD itself. Among industry participants we spoke to, there was a strong sense that PPAs compete directly with CfDs, with some going so far as saying ‘subsidised’ CfDs are crowding out the ‘unsubsidised’ PPA market. Indeed, the seasonality of the PPA market seems to be heavily influenced by the CfD auction calendar: understandably, renewable assets such as solar farms will tend to look to each market and see where they can get the best pricing and contract structure.

And the CfD is indeed tough to beat. The Government is the ultimate counterparty, offering a guaranteed 20-year deal – and with the Energy Department desperate for capacity to hit the 2030 target, the subsidies will likely be copious. Meanwhile, signing up a PPA involves the hard work of sourcing a buyer and then negotiating a bespoke contract with a variety of potential structures – inherently more effort and with higher transaction costs than a CfD.

**‘ A CfD historically offered a guaranteed 15-year contract, which the Government has just extended to 20 years on the urging of the renewables lobby ’**

## What can be done in the near term to help the PPA market scale up?

Though we do not see eye to eye with the current Government on many points of energy policy, there should be no arguments about the desirability of scaling up PPAs. After all, every one of these deals signed for new capacity gets more energy infrastructure built – and every renewable PPA drives forward the decarbonisation agenda that Ed Miliband so prizes.

275 ‘Framework Agreement RM6289’, *Crown Commercial Service*, April 2025. [Link](#). ‘New green energy agreement launched, offering price stability for sustainable power across UK public sector’, *Crown Commercial Service*, April 2025. [Link](#)

276 ‘What is a PPA? The Guide to Power Purchase Agreements’, *Pexapark*, 2025. [Link](#). ‘Homepage’, *PPAya*, April 2024. [Link](#). ‘Zeigo Power: Digital Tendering Software’, *Zeigo*, 2025. [Link](#). ‘About Us’, *Renewable Exchange*, 2025. [Link](#). ‘Homepage’, *LevelTen Energy*, 2025. [Link](#)

277 A. Rolt, ‘Welsh Water inks PPA with renewables developer Innova’, *BusinessGreen*, February 2025. [Link](#)

278 ‘Further Reforms to the Contracts for Difference Scheme for Allocation Round 7: Government Response to Policy Proposals’, *Department for Energy Security & Net Zero*, July 2025. [Link](#)



Indeed, the recent Industrial Strategy mentioned a desire to ‘support the development of the Corporate Power Purchase Agreements (CPPA) market’ and the Government has recently launched a call for evidence on the subject.<sup>279</sup>

So what could ministers do in the near term to fulfil that ambition?

One policy that could be quite helpful is an institutionalised credit guarantee, of the kind that exists in several of our European neighbours. As discussed above, counterparty risk is one of the biggest barriers to scaling PPAs beyond those corporates with an investment grade credit rating (and sometimes smaller generators as well). A guarantee facility helps mitigate that risk by underwriting a large portion of the contract, helping both sides to get more comfortable.

Norway pioneered the first facility in the early days of the European PPA market, followed more recently by Spain and France. Last year the Netherlands, Italy and the EU announced their own schemes, as recommended by the Draghi report.<sup>280</sup>

**‘ The typical renewable investment is  
c. 70-80% debt and 20-30% equity, aligning  
well with the guarantee structure ’**

The typical structure sees the state, via a public bank, guarantee 80% of the value of the PPA contract for industrial users (for example relative to spot power prices or outstanding loan value).<sup>281</sup> Underwriting only 80% of the contract ensures there is still some pain if things go wrong, thus preventing moral hazard – the typical renewable investment is c. 70-80% debt and 20-30% equity, aligning well with the guarantee structure.<sup>282</sup>

While pricing is at concessionary rates, it is also not a free lunch. In the French scheme, typical pricing is €2-4/MWh for wind and solar projects.<sup>283</sup> Indeed, such schemes are typically structured to be self-financing via these premiums (and so in a European context are considered compliant with state aid rules).<sup>284</sup> Thus given the scheme is designed to pay for itself, we would argue this is a different beast entirely to subsidies such as CfDs, despite the state being involved. In short, it is effectively a funded insurance scheme, rather than public funding per se.

If the UK wanted to set up such a scheme, the National Wealth Fund (formerly the UK Infrastructure Bank) is the natural place to house it. It is already active in the

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279 ‘Open call for evidence: Corporate Power Purchase Agreements’, *Department for Business & Trade and Department for Energy Security & Net Zero*, January 2026. [Link](#). ‘The UK’s Modern Industrial Strategy’, *Department for Business & Trade*, June 25. [Link](#)

280 ‘Guarantee fund makes sustainable energy projects financeable’, *InvestNL*, September 2025. [Link](#). ‘The Future of European Competitiveness: A Competitiveness Strategy for Europe’, *European Commission*, September 2024. [Link](#). ‘Clean Industrial Deal’, *European Commission*, February 2025. [Link](#)

281 For example minimum volumes and/or minimum electricity consumption

282 ‘5 Things you need to know about financing a renewable energy project’, *Brodies LLP*, April 2024. [Link](#)  
‘Financing 3xRenewables by 2030: Mapping global capital needs’, *Global Renewable Alliance*, November 2025. [Link](#) Page 17

283 ‘The Corporate Power Purchase Agreement (PPA) Fund: A driver for industrial consumers?’, *Bird & Bird*, November 2023. [Link](#)

284 ‘Open call for evidence: Corporate Power Purchase Agreements’, *Department for Business & Trade and Department for Energy Security & Net Zero*, January 2026. [Link](#)



market, having invested in a fund dedicated to scaling up subsidy-free solar plants (which invested in the Llanwern project), as well as financing for the project itself.<sup>285</sup> Indeed, the organisation's original strategic plan mentions an intention to 'explore opportunities to use debt or guarantees to support solar deployment across rooftop and ground-mount solar, with a focus on large-scale projects and corporate Power Purchase Agreements (PPA)'.<sup>286</sup>

Guarantees are a product that the NWF already offers, albeit on a project-by-project basis.<sup>287</sup> So the building blocks are already in place to take this idea forward. Of course, putting guardrails around the scheme would be important, not least to get the Treasury's signoff. Keeping the level of guarantee below 100% (80% in the continental examples) is an important safeguard to prevent a free-for-all of deals that wouldn't otherwise make commercial sense, as is individually assessing each transaction.<sup>288</sup> Similarly, structuring the pricing so that the scheme is self-financing ensures this is not another route to endless subsidy, and greatly limits the taxpayer's risk. And of course the scheme should be kept under regular review to ensure it is genuinely necessary as the market develops.

**‘ Many CFOs, boards and procurement teams will need time to get their heads around the idea of PPAs, and understand the risks ’**

There is also, as mentioned above, a need to educate firms about PPAs. Many CFOs, boards and procurement teams will need time to get their heads around the idea and understand the risks. While utilities and buy-side advisors serve this function today, there is likely to be a role for the Government in at least letting eligible companies know such products are available.

Finally, it's worth saying that even on the Continent, these schemes are relatively novel (Norway aside). So while we believe a guarantee has great potential and most market participants we spoke to believed it would be quite helpful, it's still relatively untested on a large scale. Some degree of trial and error is inevitable (as has happened in France), though the UK would have the continental experience to draw on. It's not a reason not to try – but it is a reason to be cautious that a guarantee would transform the PPA market overnight.

Another important move would be to exempt buyers of renewable or nuclear PPAs from the green levy costs they would otherwise pay on that power.

These levies, whether via CfDs, the Renewables Obligation or the Feed-In Tariff, are levied on all consumers in order to support the uptake of new renewables. Non-domestic consumers currently pay around two-thirds of CfD subsidy costs, for example.<sup>289</sup> But corporate buyers who take on a zero-carbon PPA are directly supporting the uptake of new renewables. Yet in today's market, they still have

285 'UK Infrastructure Bank Confirms Position as Cornerstone Investor in UK's Largest Subsidy-Free Solar', *National Wealth Fund*, August 2022. [Link](#). 'First Private Sector Deal: UK Infrastructure Bank', *National Wealth Fund*, December 2021. [Link](#)

286 'Unlocking the UK's Future – our Five-Year Strategic Plan to 30/31', *National Wealth Fund*, January 2026. [Link](#)

287 'Our products and terms', *National Wealth Fund*. [Link](#)

288 Obviously projects getting other subsidies such as a CfD shouldn't be eligible for a guarantee for the same capacity

289 'Contracts for Difference Allocation Round 7: Final Impact Assessment', *Department for Energy Security & Net Zero*, July 2025. [Link](#)



to pay these levies on all of their power. In effect, they are being charged twice, undermining the policy rationale of the levies and making PPAs artificially more expensive.<sup>290</sup>

Of course, these levies are already politically contentious. The Tories and Reform have promised sweeping reforms to cut costs for consumers. But even without such changes, Labour could and should introduce an exemption for PPA buyers which matches the volume they have contracted for new-build assets.<sup>291</sup> Such exemptions would not be a novel feature of the scheme – in fact, many energy-intensive industries are already exempt from these levies under the British Supercharger scheme and the new British Industrial Competitiveness Scheme (announced in the Industrial Strategy).<sup>292</sup> So this change would benefit businesses who are not currently exempt, namely large businesses who are not in favoured sectors and SMEs.

This change could substantially alter the economics of PPAs. Sustainable Industry estimates that for an SME manufacturer, the Renewables Obligation adds £27-32/MWh to bills, CfDs adds £7-8/MWh, and Feed-In Tariffs £6/MWh.<sup>293</sup> Pursuing a PPA could thus save businesses substantially on their energy bill – and all the more so as CfD costs continue to climb in the next few years. (If providing exemptions for all of these charges is too costly, even doing so just for the CfD would make a big difference.)

**‘ Corporate buyers who take on a zero-carbon PPA are directly supporting the uptake of new renewables. Yet in today’s market, they still have to pay carbon levies on all of their power ’**

In fact, this very exemption already exists for onsite generation, albeit inadvertently. Levies are calculated based on grid-supplied electricity, so a business installing solar panels on its roof will avoid these taxes for power coming from the panels. Our proposed exemption would simply equalise treatment for off-site generation (physical or virtual), opening up opportunities for PPAs. (One could of course envisage all sorts of other tax breaks that could help drive take-up, but this one has fairly neat policy logic.)

This policy could even go further by incentivising those who sign contracts for firm generation resources, compensating for renewables’ intermittency, and thus not putting as much strain on the grid. Renewables agreements that include batteries or dispatchable assets, or nuclear PPAs, could be exempted from Capacity Market charges. Again, there is a precedent in the exemptions given to energy-intensive industries, and again it would improve the economics of new PPA deals: CM charges are currently £3-5/MWh, but are expected to rise.<sup>294</sup>

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290 In practice, the energy utility who physically sends (‘sleeves’) the power to the consumer has to pay the levy on every MWh supplied, and thus the CfD is passed through to the end consumer. See ‘Power Purchase Agreements Guidance’, *Welsh Government*, November 2022. [Link](#)

291 Note that this idea was briefly raised in the second REMA consultation but dismissed at the time (though it is not immediately clear why)

292 ‘British Industry Supercharger gives huge boost to UK businesses’, *Department for Business & Trade*, April 2024. [Link](#). The Supercharger Scheme exempts eligible firms from a range of costs, including CfDs but also CM, RO, FIT, and 90% of network charges. Meanwhile the new British Industrial Competitiveness Scheme provided similar exemptions for firms in the ‘IS-8’ sectors, though excluding the CfD and network charges. ‘The UK’s Modern Industrial Strategy’, *Department for Business & Trade*, June 25. [Link](#)

293 N. Cox, ‘The Hidden Costs Eating Your Energy Budget: 10 Things Manufacturers Need to Know’, *Sustainable Industry*, March 2025. [Link](#)

294 Ibid.



Of course, these changes would undoubtedly have distributional consequences. The existing exemptions are mostly funded by spreading the costs on to other firms and households (the original Supercharger scheme was estimated to add £3-£5 to the average household bill).<sup>295</sup> There is certainly a wider conversation to be had about where the costs of green levies are best placed, in the context of both high energy bills and high levels of taxation.

But however these costs are allocated, there is far more policy rationale for exempting firms who are directly contributing to new generation than exempting only those whom the Government considers worth subsidising.

Finally there are some useful but admittedly more technical levers the Government could pull to help PPAs scale up. One is to reform REGOs, which are certificates issued by Ofgem to renewable generators. One REGO represents one MWh of electricity produced from renewable sources, allowing suppliers (and other interested parties) to demonstrate how green their fuel mix is.

**‘ There is far more policy rationale for exempting firms who are directly contributing to new generation than exempting only those whom the Government considers worth subsidising ’**

While many so-called ‘green tariffs’ use REGOs to evidence their renewable procurement, these have come under significant scrutiny in recent years, given that REGOs are traded independently of the electricity generated. Many corporations are therefore turning away from these ‘unbundled’ REGOs in favour of PPAs. That has sent REGO prices plummeting. Further reform to improve transparency and more accurate time matching could therefore drive demand for PPAs further.<sup>296</sup>

For example, better reporting could enable differentiation between assets that have been supported via CfDs or the Renewables Obligation, and ones that are truly ‘additional’ (e.g. via new-build PPAs). Leading businesses and organisations such as Energy UK have already called on the Government to tighten up the scheme to help drive investment in renewables.<sup>297</sup>

Similarly PPAs could be better incorporated into the Climate Change Levy scheme, which taxes businesses on their energy use. While the scheme is outdated and in need of wider reform (to incentivise decarbonisation rather than energy efficiency for its own sake), in the interim more minor changes could help drive corporate interest in PPAs. For example the Government could recognise offsite PPAs alongside onsite generation as qualifying for zero emissions factors under Climate Change Agreements (CCAs, sector-wide agreements which provide CCL discounts in exchange for reductions in energy use and emissions). And expand the number

<sup>295</sup> And these figures include network charging exemptions, so going beyond simply green levies. ‘Energy Bill Policy Statement: British Industry Supercharger – Network Charging Compensation Scheme & EII Support Levy’, *Department for Energy Security & Net Zero*, September 2023. [Link](#)

<sup>296</sup> J. Turnbull, ‘REGO: A Turning Point in Renewable Certification’, *BP Consulting*, July 2025. [Link](#)

<sup>297</sup> ‘Maximising the Corporate Power Purchase Agreement (CPPA) market to meet Clean Power 2030 and support businesses’, *Energy UK*, November 2024. [Link](#). T. McManan-Smith, ‘UK Business Leaders Call for Energy Market Reform to Boost Renewables Growth’, *The Energyst*, September 2024. [Link](#)



of firms eligible by extending CCAs to new sectors or introducing targeted CCL discounts for corporates signing a PPA with new capacity.<sup>298</sup>

## PPAs as the future for SMR deployment

It is worth, as we finish this chapter, looking specifically at SMRs. At the moment, these are a nascent technology, hence the state helping them scale up. However, just as we should encourage renewables to stand on their own two feet, so too for the next generation of nuclear. And PPAs are the perfect means by which to do this.

SMRs should be particularly well-suited for corporate customers with energy-intensive factories or data centres given their high load factors, substantial heat output (which could be sold as well), and relatively small space requirements. While the need to shut down the plant to refuel presents an issue, many designs are working to reduce the time taken for this: Westinghouse's AP300 for example promises a four-year refuelling cycle.<sup>299</sup> In terms of other advantages, some advanced reactors, such as X-Energy's, are being designed to more efficiently 'load-follow', or ramp up and down based on demand, likely broadening the pool of potential offtakers.<sup>300</sup> And though large-scale nuclear plants require very long-term agreements, the International Energy Agency estimates that SMRs could pay back their capital costs in 10-15 years, analogous to CfDs or renewable PPAs.<sup>301</sup>

**SMRs should be particularly well-suited for corporate customers with energy-intensive factories or data centres given their high load factors, substantial heat output and relatively small space requirement**

Of course, a key difference between renewables and an SMR is the amount of energy generated. A GE Hitachi 300 MW SMR operating at a 95% load factor will produce 2,498 GWh, 2.4x the energy of an offshore wind farm of the same size, and 9.5x the energy of a solar farm.<sup>302</sup> That much energy may be more than a single user could take – for scale, the entire chemicals industry used roughly 16,000 GWh in 2024.<sup>303</sup> That said, the whole point of SMRs is that they are modular – X Energy, for example, offers an 80 MW reactor which can be combined with other modules to create a larger one if necessary, while Last Energy offers 20 MW micro-reactors.<sup>304</sup> So in theory, SMRs should be able to scale up or down to meet the requirements of their offtakers.

298 Notably CCL discounts for renewable electricity have existed in the past (albeit in a complicated form), and were scrapped in 2015. A. Seely & E. Ares, 'Climate Change Levy: renewable energy & the carbon reduction commitment', *House of Commons Library*, April 2016. [Link](#). 'Review of policies to drive commercial and industrial decarbonisation', *Energy UK*, January 2025. [Link](#)

299 'AP300 Small Modular Reactor', *Westinghouse SMR*, 2025. [Link](#)

300 'Xe-100 Reactor', *X-energy*, 2025. [Link](#). 'Small Nuclear Power Reactors', *World Nuclear Association*, June 2025. [Link](#)

301 'The Path to a New Era for Nuclear Energy: Financing nuclear projects', *International Energy Agency*, January 2025. [Link](#)

302 GE Hitachi's BWRX-300 has an expected 95% capacity factor for their SMR ('BWRX-300 General Description', GE *Vernova*, December 2023. [Link](#)), equating to 2,498 GWh per year, relative to 1,025 GWh from an offshore wind farm (using historic capacity factor of 39%) and 263 GWh for a solar farm (at 10%).

303 Based on DUKES data ('DUKES 2025 Chapter 5 – Nuclear and Renewables', *Department for Energy Security & Net Zero*, 2025. [Link](#)) of total demand in 2024 of 319 TWh, of which 5% is Chemicals (per DUKES Table 5.2)

304 'Xe-100 Reactor', *X-energy*, 2025. [Link](#). 'Last Energy homepage', *Last Energy*, 2025. [Link](#)



Encouragingly, there are already examples of PPA agreements between tech companies and nuclear developers in the United States. And there are private deployments in the works here in the UK, too. Community Nuclear is a recent addition to the UK's nuclear scene, founded by the former CEO of Sellafield, which is aiming to deploy four of Westinghouse's AP300 SMRs in the Tees Valley.<sup>305</sup> These are smaller versions of the AP1000, of which six units are already in operation globally, and thus Westinghouse advertises it as the 'most advanced, proven and readily deployable SMR solution'.<sup>306</sup>

Community Nuclear is aiming to deploy these reactors as a 'fully privately funded project, with no cost or risk to the UK taxpayer'.<sup>307</sup> The demand is expected to be taken up by the green energy and chemical hub planned on the North Tees Group Estate – exactly the kind of industrial deployment case that SMRs should be brilliant for.

**‘ Encouragingly, there are already examples of PPA agreements between tech companies and nuclear developers in the United States. And there are private deployments in the works here in the UK, too ’**

Now, it's important to caveat that this project is still at a relatively early stage of development, and is by no means signed and fully financed. But still: the fact that a management team with deep experience in the UK's nuclear sector are willing to put their names to the project is exciting to say the least.

It is also not the only project looking to deploy without subsidies. Last Energy, a vendor of micro-nuclear plants (20 MW), has now announced two projects, one in South Wales for industrial customers and another at the London Gateway port.<sup>308</sup> Both projects advertise they are deploying without subsidies, and if all goes well with regulatory approvals Last Energy aims to deliver the first plant in South Wales by 2027 – a remarkably quick timeline.

And the 'standard' PPA isn't necessarily the only method of private deployment in the nuclear world. One alternative is the cost-price Mankala model as employed in Finland. There, a group of companies establish a joint venture to build a power-producing asset and proportionally share the costs of the joint venture as shareholders. In lieu of selling the power commercially or paying out dividends, the power company then sells its electricity to shareholders, proportionate to their holding, at the cost of production. This model – which now accounts for two thirds of all nuclear generation in Finland – has increased the number of operators in the industry and led to greater energy security.<sup>309</sup>

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305 'Projects', *Community Nuclear Power*, 2025. [Link](#)

306 'AP300 SMR', *Westinghouse SMR*, 2025. [Link](#)

307 'Projects', *Community Nuclear Power*, 2025. [Link](#)

308 'Last Energy Announces Project In South Wales, To Build Four Micro-Nuclear Plants To Decarbonise Local Industry', *Last Energy*, October 2024. [Link](#). 'Last Energy Partners With DP World To Bring Micro-Nuclear Power To London Gateway', *Last Energy*, September 2025. [Link](#)

309 'The Mankala cost-price model increases competition in power production', *EPV*, January 2022. [Link](#)



So while there are a variety of models and potential use cases for SMRs, private deployment on a large scale should be achievable to some degree by the 2030s (as Community Nuclear is aiming for) and on a widespread basis by the 2040s, assuming the technology lives up to its hype of course.

**‘ It’s vitally important that the Government doesn’t let SMRs fall into the same trap of subsidy-dependence as renewables, and clearly sets out the expectation now that private deployment is the long-term route to market ’**

It’s therefore vitally important that the Government doesn’t let SMRs fall into the same trap of subsidy-dependence as renewables, and clearly sets out the expectation now that private deployment is the long-term route to market. And of course the same principles should apply to any PPA, signed to cover any generating technology.



# Chapter 6: Bringing the Market to the Wider Power System

PPAs are the most obvious pro-market tool that we have to introduce competition to the energy market and wean ourselves off subsidy. But there are all sorts of other ways in which market mechanisms can bring us cheaper, more abundant and more competitively priced energy.

## The future of our gas fleet

One of the core principles we outlined above is that government will always have the core role of guaranteeing security of supply. While NESO manages the system on a day-to-day basis, the buck ultimately stops with the Government in terms of keeping the lights on. As discussed throughout this report, gas power stations play a critical role in today's system, filling in the gaps for intermittent renewables and very often setting the wholesale price of power.

However, the role of gas is changing – in 2024 gas only produced 26% of our power, and by the end of the decade the Government wants it to be 5%.<sup>310</sup> Even if that target isn't met (as we suspect), it will still be a far smaller number than today given all of the new renewable generation set to come online.

**‘ The role of gas is changing – in 2024 gas only produced 26% of our power, and by the end of the decade the Government wants it to be 5% ’**

This raises two distinct questions – over the next few years, what is the best strategy for keeping up the existing gas fleet so that it fulfils its critical role at the cheapest cost to consumers? And later this decade and into the next, what is the potential for new gas power stations to meet the surge of demand expected to come online?

### *The next few years*

Our large gas power stations (Combined Cycle Gas Turbine, or CCGT) mostly date back to the 1990s and the Dash for Gas, and thus are at or nearing the end of their designed operating life of c. 25 years. The consultancy Baringa expects that by 2030 more than 8 GW of capacity could retire, increasing to 15 GW by 2035 (relative to the 35 GW of total unabated gas the Government believes will be needed in 2030).<sup>311</sup>

310 'Britain's Electricity Explained: 2024 Review', *National Energy System Operator*, January 2025. [Link](#). 'Clean Power 2030 Action Plan: A new era of clean electricity', *Department for Energy Security & Net Zero*, April 2025. [Link](#)

311 In Baringa's baseline scenario. Baringa, 'Assessing the deployment potential of flexible capacity in Great Britain – an interim report', *Department for Energy Security & Net Zero*, February 2024. [Link](#). 'Clean Power 2030 Action Plan: A new era of clean electricity', *Department for Energy Security & Net Zero*, April 2025. [Link](#)



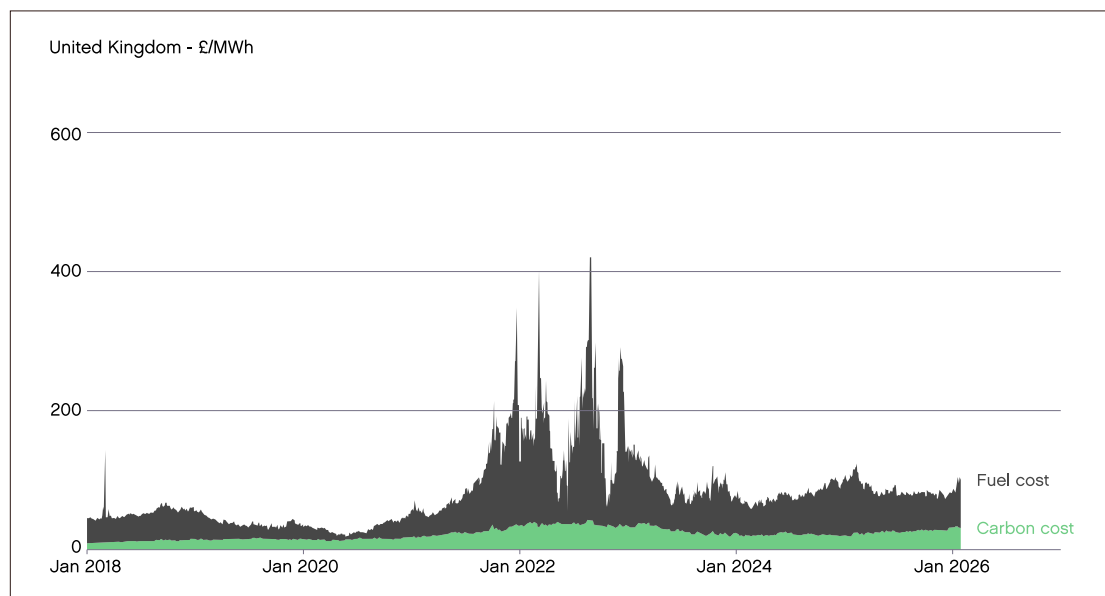
Thus keeping the lights on will require both the refurbishment of existing plants and building new ones (including some smaller ‘peaking’ plants alongside new larger CCGTs).

Both of these come at a cost to consumers, however, paid for via the Capacity Market (CM). The Government has recently agreed to lower the threshold of capex spend required to be eligible for a three-year ‘refurbishing’ CM agreement, incentivising more stations to come forward.<sup>312</sup> Meanwhile, new stations can receive CM agreements of up to 15 years, both for larger CCGTs and smaller ‘peaker’ plants – the Baringa report saw 9 GW coming online by 2035 in their baseline scenario.<sup>313</sup>

However, the CM has historically failed to deliver many large CCGTs, since the structure of the auctions favours lower-capex peaker plants. The government is consulting on changing the structure to allow more large plants to come through, but also plans to burden the industry with strict carbon emissions limits after 2034 – a decidedly mixed set of signals.<sup>314</sup>

Another issue is our current regime of carbon taxation, split between the wider ETS and the gas power specific Carbon Price Support (CPS) – both of which Claire Coutinho recently called for the Government to scrap, calculating that it would save billpayers an average of £75 per year.<sup>315</sup> Indeed, it’s worth remembering that despite a cost of living crisis, we maintain these two policies that deliberately make gas power more expensive, in the name of driving decarbonisation. As the chart below shows, at latest prices carbon costs add 52% or £32/MWh on top of the fuel cost of £71/MWh.<sup>316</sup>

### Fuel and carbon costs for gas power generation



Source: Ember Energy<sup>317</sup>

312 ‘Capacity Market: Proposals to maintain security of supply and enable flexible capacity to decarbonise’, Department for Energy Security & Net Zero, May 2025. [Link](#)

313 Baringa, ‘Assessing the deployment potential of flexible capacity in Great Britain – an interim report’, Department for Energy Security & Net Zero, February 2024. [Link](#)

314 A.Bell, ‘Ending Market Power in the Power Market’, *The Unbalancing Mechanism*, November 2024. [Link](#)  
‘Capacity Market: proposed changes for Prequalification 2026’, Department for Energy Security & Net Zero, October 2025. [Link](#)

315 Claire Coutinho, ‘Energy is Prosperity’, *Conservative Party*, October 2025. [Link](#). ‘Conservatives launch Cut My Bills campaign’, *PolicyMogul*, November 2025. [Link](#)

316 As of January 22, 2026. ‘European electricity prices and costs’, *Ember Energy*, 2026. [Link](#)

317 Ibid.



The case for removing the Carbon Price Support is indeed overwhelming. As a policy measure it was brought in to top up the ETS price and thus drive coal off of the system (by making it more expensive relative to gas).<sup>318</sup> This has now been accomplished – the last coal-fired power station shut down in 2024 (a remarkable decarbonisation achievement, making us first in the G7 to do so).<sup>319</sup>

Keeping it not only needlessly adds to our bills, but lacks any environmental logic. The entire purpose of an Emissions Trading Scheme (ETS) that spans many heavy-emitting sectors is to find and incentivise the cheapest emissions reductions – no one sector is singled out for arbitrary reasons. Yet by keeping the price support we are essentially doing exactly that – valuing emissions savings in the power sector more than in the rest of the economy – when the planet could not care less. A tonne of CO<sub>2</sub> is a tonne of CO<sub>2</sub>, regardless of who emits it. Arguably this is making the wider decarbonisation mission itself more difficult, by keeping electricity more expensive than it needs to be and thus harming take-up of EVs, heat pumps and the like.

**‘ By keeping the Carbon Price Support we are essentially valuing emissions savings in the power sector more than in the rest of the economy, when the planet could not care less ’**

There is also a case to be made against the ETS itself. It undoubtedly adds to the cost of power, substantially more than the price support (£65/tonne at latest prices vs £18/tonne). To what extent this would harm decarbonisation is debatable now that coal is gone and gas is the backbone of the system.

In technical terms it's a question of the merit order, or in other words how much would gas stations generate ahead of say interconnector imports (e.g. French nuclear or Norwegian hydroelectric) once the ETS was removed.<sup>320</sup> Frankly, this is a difficult question to answer without modelling, given that the answer will vary in each half-hour period. (Among experts we surveyed there was no clear consensus on this point.)

Removing the ETS from power stations would of course have wider implications. For starters, the Government has announced its intention to link up with the EU ETS scheme (which applies to gas and coal stations on the continent), which would make such a move difficult if not impossible.<sup>321</sup> Even in the absence of linkage, any power being sent across the interconnectors to Europe would suddenly be hit with the CBAM tariff, significantly complicating cross-border power trading.<sup>322</sup>

But the biggest issue is one of fairness to all the other sectors covered by the ETS. If the power sector is getting an exemption, why not steel, cement, chemicals and

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318 D. Hirst, 'Carbon Price Floor (CPF) and the price support mechanism', *House of Commons Library*, January 2018. [Link](#)

319 S. Twidale, 'Britain to become first G7 country to end coal power as last plant closes', *Reuters*, September 2024. [Link](#)

320 Per DESNZ data, our largest sources of imported power in 2024 were France (46%), Norway (23%), Denmark (12%), Belgium (12%), and the Netherlands (7%). The first four have less carbon-intensive power production, while the Netherlands has more carbon-intensive production – though what is coming across in each half hour will vary. 'Digest of UK Energy Statistics (DUKES): electricity', *Department for Energy Security & Net Zero*, July 2025. [Link](#) [Dukes 5.13]. 'Electricity Data Explorer', *Ember Energy*, January 2026. [Link](#)

321 P. Seddon, 'Labour to begin talks on admin fees for linking to EU carbon scheme', *BBC News*, November 2025. [Link](#)

322 'How to mitigate potential impacts of the EU Carbon Border Adjustment Mechanism', *RenewableUK*, October 2024. [Link](#)



so on? True, other sectors get many of their allocations ‘for free’ whereas the power sector does not (given that it isn’t exposed to ‘carbon leakage’).<sup>323</sup> But still, for many businesses in these affected sectors, carbon pricing can be a significant strain on their annual budget.<sup>324</sup> They would justifiably ask why gas power stations were being singled out for special treatment.

*Later this decade and into the next*

For a future Government entering power later this decade, the situation will look somewhat different to today. On the one hand, gas prices are expected to decline in the next few years as a wave of LNG export capacity comes online.<sup>325</sup> (Indeed, this may be the one hope the current Government has of making good on its pledge to take £300 off household bills, though it would deserve no credit.)<sup>326</sup> On the other, gas will have decreased substantially as a share of generation, given the huge renewables buildout that will occur over the next few years.

At which point, could a new fleet of gas power stations be the answer to our energy woes? Ed Miliband certainly isn’t going to build one. But might Claire Coutinho or Richard Tice?

**‘SSE, the owner of the Keadby 2 gas plant, estimates it would cost three and a half times as much to build today’**

Lower gas prices – if they come – would definitely make the prospect of new stations appealing, particularly as they will be more efficient than the older ones built during the Dash for Gas.<sup>327</sup> And as mentioned earlier, there is likely to be a surge of new energy demand coming online over the next two decades, which gas could help to meet. Indeed, data centres in the US are turning to gas, and reportedly tech companies here are looking at this as well, though potentially in a backup capacity or while waiting for a grid connection to come through.<sup>328</sup>

Unlike renewables, gas is of course dispatchable, meaning it can be delivered on demand. And it is far quicker to build than nuclear. The most recent large CCGT, Keadby 2, took 4.5 years to build, with another two years or so in pre-development, while smaller ‘peaking’ plants can be built in as little as one to two years (excluding pre-development).<sup>329</sup>

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323 Admittedly free allocation does effectively value carbon savings in different sectors differently, but this is intended as a transitional measure to prevent carbon leakage and will be phased out as CBAM comes into force. C. May & L. Jones, ‘New changes: the UK emissions trading scheme (UK ETS)’, *Norton Rose Fulbright*, November 2023. [Link](#)

324 A. Daniel, ‘Carbon tax is “killing manufacturing” in UK, says Ineos boss Ratcliffe’, *The Independent*, April 2025. [Link](#)

325 J. Leake, ‘Britain risks missing out on gas price lifeline’, *Telegraph*, January 2026. [Link](#)

326 M. Green, ‘Cornwall Insight reduces power price forecast for the rest of the decade’, *Solar Power Portal*, April 2024. [Link](#)

327 ‘Keadby 2 Power Station: the future of power generation in the UK’, *Siemens Energy*, June 2024. [Link](#)

328 R. Millard, T. Bradshaw, ‘Data centres look to tap UK gas pipelines to meet power demands’, *Financial Times*, August 2025. [Link](#)

329 ‘Keadby 2 Power Station: the future of power generation in the UK’, *Siemens Energy*, June 2024. [Link](#)  
‘Digest of UK Energy Statistics (DUKES): electricity’, *Department for Energy Security & Net Zero*, 2025. [Link](#)  
DUKES 5.11. ‘InterGen Achieves Commercial Operations at 300 Megawatt Spalding Energy Expansion’, *Intergen*, July 2019. [Link](#). ‘Electricity Generation Costs 2025’, *Department for Energy Security & Net Zero*, January 2026. [Link](#). [Annex A]



This would seem to suggest that we can build new gas capacity relatively quickly, as with renewables. But it's not so simple. The market for gas turbines is tight at the moment – there are only three major suppliers for turbines, and a surge in demand means order books are filling up towards the end of the decade.<sup>330</sup> This has naturally driven up prices: SSE, the owner of Keadby 2, estimates it would cost three and a half times as much to build today.<sup>331</sup> And while gas prices may be going down, carbon prices will be going in the opposite direction as decarbonisation slowly grinds forward (assuming the ETS stays in its current form, which of course it might not under a new Government).

However, the largest impediment to building a new fleet of large gas power stations is likely to be their lower running hours. CCGTs are designed to run at high load factors. That's also when the economics make sense: NESO estimates that a CCGT in 2035 running at a 10% load factor will have nearly double the levelled cost of one running at 50% or 90%, regardless of carbon costs.<sup>332</sup>

**‘ Just as we should push renewables and nuclear to be subsidy free, the same applies for gas generation. Indeed, the core principle underlying our energy market should be that all mature forms of new capacity should be able to compete without the distortions of subsidies ’**

However, as mentioned above, gas's share of the market has been eaten away at by renewables in recent years – a process that Ed Miliband is determined to continue. Unless a Tory or Reform government actively shuts down the wind farms, a new gas power station coming online in 2030 might expect to operate only 30% of the time, given all the renewables that will then be in place.<sup>333</sup> While this would be perfectly reasonable for smaller peaker plants (which tend to be less efficient and thus more costly to run), a large CCGT would likely struggle to recover its capital costs efficiently at such low load factors.

As discussed above, the purpose of the Capacity Market is to subsidise gas generators (and other dispatchable sources such as batteries) in order to make up for this effect. To stand up a new fleet of CCGTs to meet rising demand, in place of renewables or nuclear, might well require ever larger subsidies to make the maths stack up for investors. Indeed, in a sign of the times, the Government has just proposed raising the subsidy amount that new dispatchable stations, including CCGTs, can be paid to ensure new plants can get built.<sup>334</sup>

To throw subsidies at the market to ensure security of supply is one thing. Giving out large subsidy payments to gas generators to meet new demand would be something else entirely.

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330 Stapczynsky et al, 'AI-Driven Demand for Gas Turbines Risks a New Energy Crunch', *Bloomberg*, October 2025. [Link](#)

331 J. Yeomans, 'SSE boss: 'We need new power plants, and renewables are cheapest'', *The Times*, January 2026. [Link](#)

332 'FES 2025 Economics Annex', *National Energy System Operator*, December 2025, p.15, fig.5. [Link](#)

333 This figure is difficult to predict, but industry experts suggested 30% as a good ballpark figure, and this is also the load factor that DESNZ used in their recent Electricity Generation Costs report as representative of a new mid-merit plant. 'Electricity Generation Costs 2025', *Department for Energy Security & Net Zero*, January 2026. [Link](#)

334 'Capacity Market: proposed changes for Prequalification 2026', *Department for Energy Security & Net Zero*, October 2025. [Link](#)



Just as we should push renewables and nuclear to be subsidy free, the same applies for gas generation. Indeed, the core principle underlying our energy market should be that all mature forms of new capacity should be able to compete without the distortions of subsidies, with the cheapest winning out.

Of course, if gas can stand on its own two feet, by all means we should welcome new gas generation. Data centres for example could conceivably sign PPAs with gas generators, as is happening in the US, helping to alleviate the load factor issue. But doing so on a widespread basis would require overcoming a number of economic hurdles – and that’s even before getting into the question of carbon prices and the future decarbonisation trajectory.<sup>335</sup>

**‘ High voltage transmission lines operate at 400 kilovolts (kV) to reduce the energy loss resulting from the resistance that occurs over long distances ’**

## The transmission & distribution networks

### *Transmission*

Though this paper has mostly discussed generation, the grid is also of vital importance and deserving of our attention.

To remind the reader, the GB grid is split between national transmission lines and more local and regional distribution networks. The high penetration of renewables, with their inherent intermittency and dispersed geography, is placing new strains on a system designed and built nearly 70 years ago, culminating in what has been dubbed ‘the Great Grid Upgrade’ – the necessary extension and expansion of grid capacity to sufficiently cater for growing electricity supply and demand.

High voltage transmission lines operate at 400 kilovolts (kV) to reduce the energy loss resulting from the resistance that occurs over long distances.<sup>336</sup> The three private companies (more commonly referred to as Transmission Operators, or TOs) that own these lines act as natural monopolies and are hence subject to price-control regulation by Ofgem, following its rather convoluted RIIO framework, standing for Revenue = Incentives + Innovation + Outputs.<sup>337</sup>

The transmission grid’s great challenge right now is that as electrification increases, our current infrastructure cannot provide enough capacity to accommodate the power generated by renewables, leading to recurrent ‘constraints’. And these constraints are proving to be rather costly: to avoid overloading the grid in 2024, more than a billion pounds was paid to redispatch the system.<sup>338</sup>

335 The Government may introduce emissions limits on gas power stations in future, as outlined here: ‘Reforms outlined for Britain’s capacity market to secure a clean energy future’, *Department for Business, Energy & Industrial Strategy (BEIS)*, January 2023. [Link](#)

336 ‘Transmission Networks’, *SSE*, 2025. [Link](#)

337 RIIO-3 Final Determinations for the Electricity Transmission, Gas Distribution and Gas Transmission Sectors’, *Ofgem*, December 2025. [Link](#)

338 D. Wildash, ‘The Scottish Boundary bottleneck that’s costing the UK £1bn a year’, *Apartura*, May 2025. [Link](#)



Geography also plays a role in the expense. Nearly half the UK's wind capacity is based in Scotland and channelling that power down to meet demand in the south of the UK hits an acute bottleneck at the border with England – the B6 Boundary.<sup>339</sup>

In effect, the separate Scottish and English grids represent major ring roads that don't have enough connections to cater for the ever-growing traffic now moving between them. If left unchecked, NESO predicts that curtailment costs arising from the B6 bottleneck could reach as much as £3bn annually.<sup>340</sup> That is the worst-case scenario, and efforts to alleviate the constraints that the boundary imposes are currently underway through the Eastern Green Link projects, each laying down 2 GW HVDC (high voltage direct current) lines connecting Scotland to the North of England via the North Sea.<sup>341</sup>

If more transmission capacity is required, then the next question is: 'Who builds it?'

As mentioned earlier, the Transmission Operators (TOs) have natural monopoly power due to their licensed status. But the construction of new transmission lines has been increasingly opened to market competition. The most pertinent development in this area has been the introduction of the Competitively Appointed Transmission Owner (CATO) regime, enabling independent developers to competitively bid for licences to build, own and operate new onshore transmission infrastructure.<sup>342</sup> Ofgem is currently finalising the framework that will guide this regime and will identify the initial projects to be awarded a CATO licence from NESO's next holistic network plan in Summer 2026.<sup>343</sup>

**With the wait for a connection to the grid now five and a half years on average, the ability for private entities to construct and operate new transmission infrastructure is unfortunately very limited**

A similar regime exists for offshore wind installations, known as the Offshore Transmission Owner (OFTO) licence, although it differs in that the transmission infrastructure is built by the wind farm developer and then later acquired by the winning bidder, with revenues dictated by subsequent availability.<sup>344</sup> So far the regime has awarded licenses for 28 transmission projects and has seen the cost of capital reduce by several percentage points, with £12bn invested so far.<sup>345</sup>

While these developments are welcome, they only provide market competition in the provision of new transmission infrastructure, still relying upon central direction from Ofgem and NESO on where new capacity is needed. With the current wait for a new connection to the grid now five and a half years on average, the ability for private entities

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339 'Scotland delivering 48% of UK's historic 30 GW wind power milestone', *Scottish Renewables*, August 2024. [Link](#)

340 'Constraints Collaboration Project', *National Energy System Operator*, 2025. [Link](#)

341 'Eastern Green Link 1: Torness to Hawthorn Pit', *Eastern Green Link*, 2025. [Link](#). 'Homepage', *Eastern Green Link 2*, 2025. [Link](#)

342 D. Trethowan, 'CATO regime will drive innovation and improve efficiency', *Pinsent Masons*, December 2024. [Link](#)

343 'Onshore early competition in electricity transmission – Stakeholder update December 2025', *Ofgem*, December 2025. [Link](#)

344 Tong et al, 'Offshore Transmission Owners', *Grant Thornton*, November 2024. [Link](#)

345 Ibid.



to construct and operate new transmission infrastructure – in the way that private firms built the railways during the Industrial Revolution – is unfortunately very limited.

Adam Bell of Stonehaven has suggested that reform of the licensing regime could allow developers to build infrastructure that is commercially viable, with minimal government involvement in agreements between developers and the existing TOs over shared use of private infrastructure.<sup>346</sup> This would allow private developers to meet demand for new transmission without explicit directions from NESO and could allow for expedited grid expansion beyond that already being undertaken by the National Grid.

Worryingly, however, the current Government appears to be moving in the opposite direction. It has commissioned NESO to produce a Strategic Spatial Energy Plan that will ‘map the potential locations, quantities and types of electricity generation and storage infrastructure over time, modelled across a range of plausible futures’.<sup>347</sup> In other words, old school central planning appears to be back in fashion.

**‘ Rather than centrally planning all transmission infrastructure, the state could define zones where generation is overwhelmingly likely to be located ’**

So far only the methodology that will underpin NESO’s conclusions has been released, with the full plan to be published later this year.<sup>348</sup> But while some strategic planning may be necessary to ensure transmission keeps up with new generation, there is a huge risk of making the wrong decisions (due to imperfect information or political influence), or artificially constraining certain types of generation.<sup>349</sup>

Moreover, a long-term plan would carry most heft if it was underpinned by cross-party consensus. However, both the Conservatives and Reform UK are offering differing or even antagonistic approaches to Labour’s – meaning it is likely that the plan would be completely rewritten should either of those parties win power.<sup>350</sup>

Perhaps there is a middle ground. Rather than centrally planning all transmission infrastructure according to a pre-ordained generation mix, the state could look to define some zones where generation is overwhelmingly likely to be located and build anticipatory infrastructure – with the rest of the system open to market forces.

Indeed, Texas provides such a model. Faced with increasing grid congestion in serving the big cities in the eastern half of the state, the Texan government created Competitive Renewable Energy Zones (CREZ).<sup>351</sup> These were areas defined as having high renewable potential according to a number of factors – one of which was the

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346 A. Bell, ‘Set the Pylons Free’, *The Unbalancing Mechanism*, January 2025. [Link](#)

347 ‘Strategic Spatial Energy Plan: commission to NESO’, *Department for Energy Security & Net Zero*, October 2024. [Link](#)

348 ‘Review of electricity market arrangements (REMA): Summer update’, *Department for Energy Security and Net Zero*, July 2025. [Link](#)

349 ‘Strategic Spatial Energy Planning (SSEP)’, *National Energy System Operator*, 2025. [Link](#)

350 K. Stacey, ‘Conservative party to ditch commitment to net zero in UK by 2050’, *The Guardian*, March 2025. [Link](#). ‘Reform would scrap “net stupid zero” policies, says deputy leader’, *BBC News*, March 2025. [Link](#)

351 ‘Transmission & CREZ Fact Sheet’, *Power Up Texas*, December 2018. [Link](#)



level of financial commitment already made by wind farm developers. State-funded transmission lines were built to these locations, predominantly in West Texas and the Texas Panhandle, in anticipation of future wind generation.<sup>352</sup> The model is generally seen to have worked well, with Texas now among the leaders in renewables deployment in the US, and could serve as a useful template for Britain – providing the benefits of building cables in advance of demand, without the requirement to centrally plan the entire system.<sup>353</sup>

### *Distribution*

High voltage electricity, having travelled through the transmission lines across the country, is then converted into lower voltages as it enters the local distribution networks that ultimately power homes and businesses. In the UK there are 14 geographically defined regions, each owned and operated by a licensed Distribution Network Operator that, like the three national transmission companies, is again tightly regulated by Ofgem and the RIIO framework.<sup>354</sup>

**‘ The Government has decided against adopting locational marginal pricing, under which the national wholesale electricity market would be split into geographic zones with differing prices ’**

However there is a surprising amount of competition to be found in the distribution networks. Though the DNOs act as sanctioned monopoly operators, since the early 2000s Ofgem has also granted licences to Independent Distribution Network Operators (IDNOs), who provide competition for the construction of new, ‘last mile’ extension lines within the distribution network, such as new housing developments or generation.<sup>355</sup> The effects of this regime have been significant, with 70-80% of new connections administered by IDNOs and the number of customers serviced through them now standing at approximately 1.5 million.<sup>356</sup> Similarly Independent Connection Providers (ICPs) can compete to build the physical infrastructure, which once completed is turned over to the DNO or IDNO to own and maintain.<sup>357</sup>

That said, the role of the IDNOs is generally limited to ‘last mile’ connections, rather than being able to reinforce their host distribution networks.<sup>358</sup> Thus the proposal above to allow developers to build grid infrastructure on their own should be extended to distribution as well, subject to a commercial agreement with the relevant DNO.

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352 Schumacher et al, ‘Moving Beyond Paralysis: How States and Regions Are Creating Innovative Transmission Projects’, *National Renewable Energy Laboratory*, October 2009. [Link](#)

353 The SSEP will include a ‘low regrets’ pathway alongside the other pathways (of which the Secretary of State will choose one), but given the intent of the SSEP as a whole it seems unlikely that this would mirror the hybrid approach envisaged above.

354 ‘RIIO-2 Electricity Distribution Summary Annual Report: 2023-34’, *Ofgem*, April 2025. [Link](#)

355 E. Warburton, ‘Open letter on regulatory arrangements for independent distribution network operators’, *Ofgem*, October 2023. [Link](#)

356 Ibid.

357 B. Brading, ‘Independent Connection Providers: Benefits and Risks for Businesses’, *Business Energy Deals*, 2026. [Link](#)

358 See for example the definitions of Contestable vs Non-Contestable works for National Grid Electricity Distribution ([here](#)), SSEN ([here](#)) or Northern Powergrid ([here](#))



## *Improving the current system of transmission and distribution charging*

The Government has decided against adopting locational marginal pricing, under which the national wholesale electricity market would be split into geographic zones with differing prices.<sup>359</sup>

While we still believe that locational pricing is the right decision over the longer term, we accept that the current Government is unlikely to move on the issue. Thus the next few paragraphs will focus on what can be done to strengthen the existing regime.

At present there is a geographic element of the cost of electricity to both generators and consumers – Transmission Network Use of System (TNUoS) charges and in the case of distribution, DUoS charges.<sup>360</sup> These are the annual charges National Grid (in England) or a local DNO uses to cover the cost of maintaining and operating their network. In the case of TNUoS, these impose higher rates on generators that operate in more remote areas of the country like northern Scotland – therefore providing signals about network costs.

**‘ At present there is a geographic element of the cost of electricity to both generators and consumers – Transmission Network Use of System (TNUoS) charges and in the case of distribution, DUoS charges ’**

However, a side effect is that TNUoS charging is currently too volatile year-on-year, resulting from a complicated methodology and short-term forecasts that seek to predict the demands placed on the evolving grid of today rather than the demands of the grid in 10 or 20 years.<sup>361</sup> This makes it difficult for investors in new generation to plan, reducing TNUoS’ effectiveness as an investment signal.

Reducing this volatility is a focus of the current REMA reforms, via a number of mechanisms. However, these plans are still being developed, with the aim to deliver them ‘within this Parliament’ – creating uncertainty for investors in the interim.<sup>362</sup>

Moreover, there is the additional matter of shallow versus deep connection charging. The current system is mostly ‘shallow’, and thus limits charges for new connecting parties to the immediate infrastructure of which they are the sole users. The latter would charge not just for the primary assets but also the additional upstream infrastructure that reinforces it.<sup>363</sup>

Put another way, a shallow connection is akin to charging for the offramp that connects a user to the main highway (i.e. the grid), whereas deep connections charge for both the cost of the offramp and the highway. Currently the transmission regime is shallow, while generators connecting at a distribution level face a ‘shallow-

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359 ‘Review of electricity market arrangements (REMA): Summer update, 2025’, *Department for Energy Security and Net Zero*, July 2025. [Link](#)

360 ‘Review of electricity market arrangements (REMA): Summer update, 2025’, *Department for Energy Security & Net Zero*, July 2025. [Link](#)

361 ‘Energy UK high-level views on Locational Marginal Pricing’, *Energy UK*, August 2023. [Link](#)

362 ‘Review of electricity market arrangements (REMA): Summer update, 2025’, *Department for Energy Security & Net Zero*, July 2025. [Link](#)

363 CEPA, ‘Quantitative analysis of Ofgem Access Options: Connection Boundary and TNUoS SDG’, *Ofgem*, June 2021. [Link](#)



ish' charge that requires the connector to make a percentage contribution towards reinforcement costs, with the remainder socialised through DUoS charges.<sup>364</sup>

The problem with shallow connection charges is that, to use the highway example above, generators who locate remotely from the main transmission network aren't liable to pay for the full cost of constructing the necessary highway infrastructure to feed into their connections. The cost is instead socialised through the relevant use charges. This is partly to avoid discouraging new connections (and thus investment), but it is also partly down to the Connect and Manage regime introduced under the Coalition Government in 2010.<sup>365</sup>

Faced with the issue that reinforcement lagged the pace that new generators were ready to connect, Connect and Manage allowed these grid users to connect ahead of time in order to reduce the waiting time for a connection and therefore encourage investment, which has indirectly entrenched the shallow charging regime.<sup>366</sup> However, the downside is that it puts the wrong incentives on new generators when considering where to locate, given they don't have to bear most of the costs of upstream reinforcements.

‘ Taking Sweden as an example, the country is divided into four zones from north to south. Like us, it has more production than consumption in the north, and vice versa ’

The Labour Government is currently looking to deepen connections in future as part of the REMA process.<sup>367</sup> Any move that provides clearer signals regarding the locational costs of generation is welcome.

A more novel idea to address connection charging would be to auction connection capacity – a process that is currently being rolled out in Romania.<sup>368</sup> There, all new generation and storage facilities greater than 5 MW will have to bid for capacity for a 10-year period, with the cost of reinforcement works setting the auction start price.

A connection auction is a relatively untested idea, though it hails from solid economic foundations. Namely, connection capacity is a scarce resource, especially in the current moment, but instead of picking winners (as Labour is doing), the auction will let the market determine who should be connected and at what price.

Interestingly, NESO had considered holding a one-off capacity auction in 2023, but discounted it on the grounds that it would take too long to implement.<sup>369</sup> Should connection auctions prove viable, it's a model that Britain should look to emulate.

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364 'Access and Forward-Looking Charges Significant Code Review: Final Decision', *Ofgem*, May 2022. [Link](#)

365 National Grid, 'Connect and Manage Guidance', *National Energy System Operator*, March 2013. [Link](#)

366 Ibid.

367 'Review of electricity market arrangements (REMA): Summer update, 2025', *Department for Energy Security & Net Zero*, July 2025. [Link](#)

368 V. Radu & R. Diaconeasa, 'Romania shifts towards auction-based mechanism for grid access', *CMS Law-Now*, August 2024. [Link](#). And P. Jowett, 'Romania's grid operator publishes rules for capacity auctions', *PV Magazine Energy Storage*, October 2025. [Link](#)

369 'GB Connections Reform', *National Energy System Operator*, April 2024. [Link](#)



### *A move to locational pricing over the medium term*

While all of the above reforms would be helpful, none of them replace the underlying issue of our current national wholesale price. They would provide sharper signals as to where a new generator should be sited, but once that station is generating it would still receive the same price as anyone else in the country.

In other words, a single national wholesale price essentially pretends that the system can handle any power flow to anywhere – when that is emphatically not the case, as demonstrated above. In practice, the system operator has to ‘redispatch’ the system to account for transmission constraints, at huge costs to consumers.

A system of locational pricing – as exists in markets across the world – would fundamentally change the picture. Great Britain would be divided into either a number of zones (so called ‘zonal pricing’), or many individual nodes (‘nodal pricing’), with each individual zone or node functioning as its own market, with its own price.

**‘ A move to locational wholesale pricing in Great Britain could generate net consumer benefits of £28bn to £51bn between 2025 and 2040 in a nodal model, and £15bn to £31bn in a zonal system ’**

Taking Sweden as an example, the country is divided into four zones from north to south. Like us, it has more production than consumption in the north, and vice versa.<sup>370</sup> At times when demand in the south is low (such as nights and weekends), there are no bottlenecks on the grid, and thus the country has one uniform price. However, when demand is higher and bottlenecks do occur, the price differs between zones, reflecting the relative scarcity of electricity. Both generators and consumers thus have far ‘sharper’ price signals to respond to, in real time, about the value of electricity. The benefit, in a word, is efficiency.

Locational pricing would thus complement – and go beyond – the reform of investment signals such as TNUoS by providing the operational signals that only a market can deliver. While the former may help steer where new generation is built, they cannot shape how the system runs once those assets are connected. Congestion is dynamic, shifting by the hour as weather patterns, demand and network conditions change, and only a market design that reflects those real-time constraints can guide generation and demand to respond efficiently.

By embedding these locational signals directly into wholesale prices, rather than relying on administrative redispatch, Britain would incentivise generation where it is most valuable, use the existing network more efficiently, and significantly reduce constraint costs.

Moreover, the net effect to consumers should be cheaper bills across the board. FTI Consulting’s modelling concluded that a move to locational wholesale pricing in Great Britain could generate net consumer benefits of £28bn to £51bn between 2025 and 2040 in a nodal model, and £15 to £31bn in a zonal system.<sup>371</sup>

370 P. Holmberg & T. Tangerås, ‘The Swedish electricity market – today and in the future’, *Riksbank*, 2023. [Link](#)

371 ‘Assessment of locational wholesale electricity market design options in GB’, *FTI Consulting & Energy Systems Catapult*, October 2023. [Link](#)



Now, the extent to which consumers (whether households or businesses) would be exposed to such price differentials would be politically contentious, with fears of a ‘postcode lottery’. But even if consumers were fully shielded from any such impacts, and households across the country faced similar prices as they do today, FTI’s modelling suggests there would still be net consumer benefits.<sup>372</sup>

The main arguments marshalled against zonal pricing during the recent debate on the issue in Whitehall were an increase to the cost of capital (via the uncertainty created by such a move), and a hiatus of investment, just as the Government is sprinting at full pelt towards its Clean Power 2030 goal. Understandably, many generators who stood to lose money were against the idea, and one imagines that the risk of jeopardising the 2030 target was a powerful argument with the current Government.

The risk of a transition is real – investors need certainty, and a move to zonal pricing would create uncertainty and disruption, and if not handled carefully could indeed raise risk premiums and thus the cost of capital. But it is still a good idea.

While some form of locational pricing is clearly the right move, any transition must be carefully choreographed to avoid destabilising investment. That means setting out the new market design well in advance, and providing clear transitional protections so that existing projects are not blindsided.

**‘ Britain must build vast quantities of new generation and flexibility out to 2050, and the physical realities of the grid will not become any gentler ’**

This issue is not going away – Britain must build vast quantities of new generation and flexibility out to 2050, and the physical realities of the grid will not become any gentler. The choice, ultimately, is between managing this transition deliberately and well, or being forced into it under greater pressure later on.

Locational pricing also has implications for a future PPA-led system, and here too a balanced approach is needed. For the state-directed system Britain has today – and for the one it is rapidly becoming – locational pricing is clearly the right long-term direction. But if a future government follows our recommendation to move more of the market onto long-term PPAs, that will introduce an additional layer of complexity: corporates and suppliers would need to manage locational risk alongside the familiar challenges of volume, shape and counterparty risk.

These complications are not insurmountable – PPAs function perfectly well in zonal and nodal markets elsewhere, for example through locational hedging products, virtual structures, or contracting within the same zone. But it is also true that in such markets, hedging tools for locational risk rarely extend over the full 10- or 15-year horizon of a typical PPA, which creates a mismatch that buyers and sellers must accommodate.<sup>373</sup> This reinforces the case for a phased, carefully signalled implementation of locational pricing: one that protects existing contracts and gives markets time to develop appropriate risk-management tools.

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<sup>372</sup> Ibid, page 265

<sup>373</sup> Locational hedging products in the United States (FTRs) are available for example three years in advance in the PJM market (see [here](#)) and EPADs in the Nordics are available 3-4 years out ([here](#))



## Retail markets

Four years ago, Russia's invasion of Ukraine sparked a global energy crisis – one acutely felt in the UK due to its exposure to international gas markets. Energy bills skyrocketed, suppliers went bankrupt, and Ofgem leaned on the tool that still dominates the market today – the energy price cap.

Originally introduced in 2017, the cap was meant to guard against the so-called 'loyalty penalty' hitting consumers: the effect of retailers transferring their customers from fixed tariffs, which had offered lower rates to entice customers to join in the first place, to standard variable tariffs that were uncompetitive.

Instead, as the CPS has highlighted, the price cap morphed with the arrival of the energy crisis into a market-wide price control. By April 2023, more than 29 million households were covered by the cap and switching rates had collapsed.<sup>374</sup> Its effects were strongly amplified by Ofgem's use of the Market Stabilisation Charge (MSC), which forced suppliers to reimburse other suppliers for prying their customers away. This was blatantly anti-competitive and the regulator admitted as much, despite reasoning that it was necessary to prevent further insolvencies in the market.

‘ The price cap morphed with the arrival of the energy crisis into a market-wide price control ’

Fast-forward to today and the picture is more nuanced. The MSC expired in March 2024 and price competition has begun to return in earnest.<sup>375</sup> The cheapest fixes are around 15% less than the January price cap, according to Money Saving Expert, while switching rates are also recovering, though they remain well below their pre-crisis peak.<sup>376</sup>

Whether this slow convalescence will accelerate or stall remains to be seen. What can be said is that the price cap is now, depressingly, a fact of life in the energy retail market in the UK – so much so that retaining it was a Tory manifesto commitment at the last election, while Labour obviously have no plans to scrap it.<sup>377</sup> Nonetheless, there is still a case, and scope, for greater competition. For example, six firms constitute 91% of the retail market – nearly 20 percentage points higher than in 2020.<sup>378</sup> Admittedly, the composition of this group has changed (Octopus Energy is a relative newcomer, for example). But choices outside these six suppliers are increasingly limited: the number of domestic energy suppliers has collapsed from 49 pre-crisis to only 18 as of September 2025.<sup>379</sup>

And of course this concentration was boosted by Ofgem's Supplier of Last Resort (SoLR) mechanism, which in the event of supplier insolvency, ensured continuity of supply for customers by transferring them to other firms. British Gas acquired

374 D. Smith, 'The Case Against the Energy Price Cap', *Centre for Policy Studies*, August 2023. [Link](#)

375 'Future of Market Stabilisation Charge after March 2024', *Ofgem*, October 2023. [Link](#)

376 'Should I fix my energy or stay on the Price Cap?', *Money Saving Expert*, January 2026. [Link](#) 'Retail market indicators: Number of domestic customers switching supplier by fuel type (GB)', *Ofgem*, 2026. [Link](#)

377 'Manifesto 2024: Clear Plan, Bold Action, Secure Future', *The Conservative and Unionist Party*, June 2024. [Link](#)

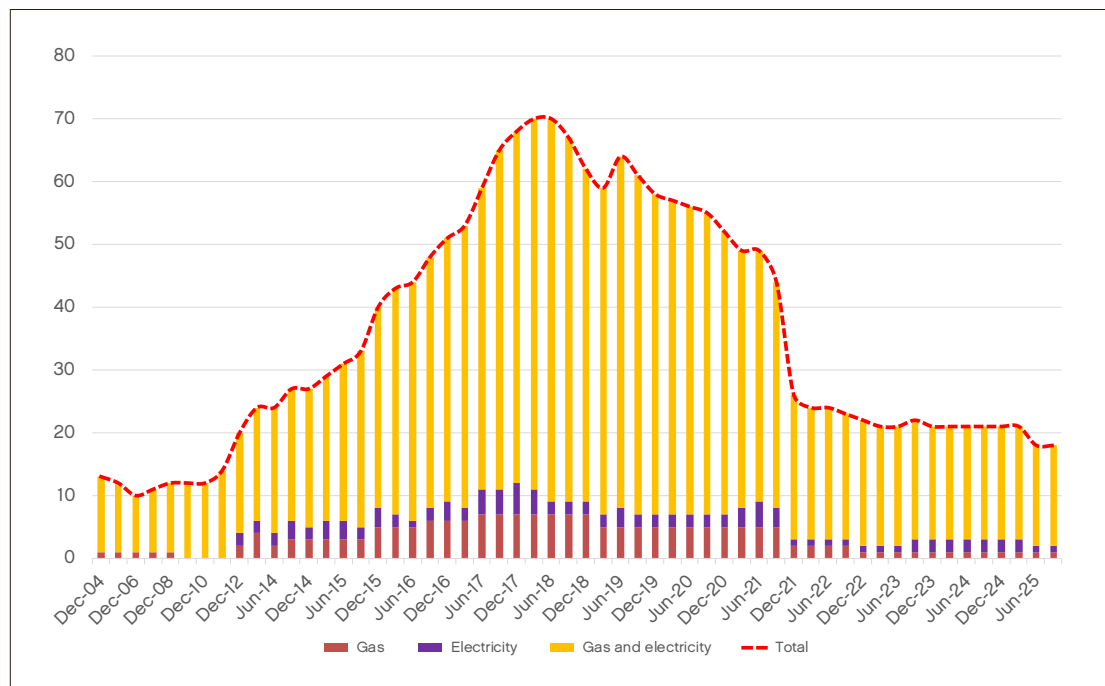
378 'State of the market report', *Ofgem*, April 2025. [Link](#)

379 'Retail market indicators: Number of active domestic suppliers by fuel type (GB)', *Ofgem*, 2025. [Link](#)



680,000 customers; E.ON had 248,000 transferred; Octopus Energy 580,000.<sup>380</sup> Tellingly, there have been no new entrants to the retail market since the third quarter of 2023.<sup>381</sup>

### Number of active domestic suppliers by fuel type



Source: Ofgem<sup>382</sup>

Even with the misguided price cap in place, there are a number of other reforms that could boost competition. One is market-wide half-hourly settlements (MHHS), where suppliers, instead of relying upon annual or quarterly meter readings, can leverage the rollout of smart meters to align household energy consumption with the half-hourly settlements made in the wholesale market.

Currently, suppliers must purchase from the wholesale market using profiles of typical household demand. Since these aren't precise estimates, the discrepancies between the volume purchased and the amount actually used create a cost. This is absorbed in the first instance by the system operator, and ultimately by consumers.

With more data available in real time, suppliers will be able to supply electricity in more accurate quantities to match demand, realising greater efficiencies that can be passed on to consumers (saving between £1.6bn and £4.5bn by 2045).<sup>383</sup> It would also create the right conditions to further expand time-of-use tariffs, whereby the unit price of electricity changes depending on the time of day.

For example, many suppliers today offer EV tariffs, whereby an EV is charged overnight when electricity is cheapest, rather than from the moment one arrives

380 National Audit Office, 'The energy supplier market', *Department for Business, Energy & Industrial Strategy (BEIS) and Ofgem*, June 2022. [Link](#)

381 'Retail market indicators', *Ofgem*, 2025. [Link](#)

382 'Retail market indicators', *Ofgem*, 2025. [Link](#)

383 Environmental Audit Committee, 'Enabling sustainable electrification of the economy: Government Response', *House of Commons*, December 2024. [Link](#)



home during peak times in the evening prior. Such tariffs (also referred to as 'demand flex') are entirely voluntary, and designed for consumers to save money by responding to price signals. By aligning suppliers' purchasing strategies with actual demand, MHHS should open up far more scope for innovative tariffs, increasing competition and the potential for savings.

Another helpful move would be the removal of supplier exclusivity and the introduction of secondary suppliers. This would enable more than one company to supply electricity to households – for example, consumers could have one supplier for their main household electricity and a different supplier (and tariff) for their heat pump or EV.<sup>384</sup> This could be a powerful driver of greater competition, particularly if paired with purchases for new kit: for example an electricity tariff for 500 miles of driving per month being bundled alongside a new EV.<sup>385</sup>

There are of course caveats and stumbling blocks to these proposals. The timetable for the introduction of half-hourly settlements has been delayed to mid-2027.<sup>386</sup> The Smart Meter rollout won't be complete until 2030 (though Ofgem insists that this won't delay the introduction of half-hourly settlements) and there are no plans to reconsider the rules on secondary suppliers as of yet.<sup>387</sup>

**‘ There are over 10,000 pages of energy industry codes, more than four times the length of the complete works of Shakespeare ’**

Finally, there is Ofgem itself. Energy UK has calculated that its headcount and annual costs have risen by 120% and 200% respectively over the last decade – far above levels in the energy sector or comparable regulators.<sup>388</sup> And yet Ofgem's recent performance has been mediocre at best; sluggish and at times incoherent, seemingly more focused on building its public profile than ensuring effective economic regulation, and prone to kneejerk decisions that seem poorly thought through. It has also appeared increasingly vulnerable to political pressure, undermining the case for independent regulation.

Ofcom is also largely responsible for the ever-growing thicket of regulation in the energy sector. There are over 10,000 pages of energy industry codes, more than four times the length of the complete works of Shakespeare.<sup>389</sup> As a result, the cost to serve an account in the UK is around double the level in France.<sup>390</sup> And that's if suppliers can make sense of the rules in the first place – Energy UK reports that innovative companies that want to enter the markets often find 'a regulator that is unwilling to explain its own rules'.<sup>391</sup>

Thus if the energy markets are to succeed, our regulatory regime requires urgent change. At a minimum Ofgem needs substantial reform and a change in mindset,

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384 'Innovating beyond retail: reaching Net Zero consumer energy', *Energy Systems Catapult*, March 2024. [Link](#)

385 'Reinventing Retail Energy', *Stonehaven*, September 2023. [Link](#)

386 Environmental Audit Committee, 'Enabling sustainable electrification of the economy: Government Response', *House of Commons*, December 2024. [Link](#)

387 Ibid.

388 'The future of energy regulation: more efficient, lower cost, better outcomes', *Energy UK*, October 2025. [Link](#)

389 Ibid.

390 Ibid.

391 Ibid.



in line with the Government's target to reduce the administrative costs of regulation by 25% and for regulators to prioritise growth.<sup>392</sup> Indeed, the Government is currently undertaking a review of Ofgem, although the call for evidence closed more than a year ago with still no response from Government.<sup>393</sup>

On this front, bold proposals have been made. Some have called for Ofgem to be broken up. Energy UK recently called for Ofgem to be slimmed down to focus only on regulation of network firms, while transferring the responsibility for protecting consumers to the Consumers & Markets Authority (CMA).<sup>394</sup>

Given the CMA's focus on competition and consumer protection and reputation for independence, this has strong appeal. That said, the CMA is not currently set up to regulate individual sectors on an ongoing basis, so this would likely require a fair amount of reform to achieve. (Though there is some precedent under the new Digital Markets Act, which gives the CMA new powers to regulate large tech firms.)<sup>395</sup> Yet while we are agnostic on how it happens, it is clear that the current regulatory regime needs significant reform if it is to deliver effective competition for consumers.

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392 'New approach to ensure regulators and regulation support growth', *HM Treasury*, October 2025. [Link](#)

393 'A review of Ofgem: call for evidence', *Department for Energy Security & Net Zero*, December 2024. [Link](#)

394 'The future of energy regulation: more efficient, lower cost, better outcomes', *Energy UK*, October 2025. [Link](#)

395 'DMCC Act: New digital regime for the UK', *Ashurst*, August 2024. [Link](#)



# Chapter 7: The Post-Decarbonisation Era

While the preceding chapters have primarily focused on the near-term, this chapter will look to the future. As set out in Chapter 2, we will soon be entering a new phase in power, where decarbonisation is (mostly) complete, and the primary force driving new generation across the country will be rising demand. In this era we believe it will be more important than ever that the market, rather than Whitehall, is deciding what gets built – if we're serious about cheap power, that is.

Indeed, now is the time to be having these arguments – as there are those on the Left who are looking at the same mix of problems we have identified in this paper and coming to the opposite conclusion.

**‘In the coming era, it will be more important than ever that the market, rather than Whitehall, is deciding what gets built – if we're serious about cheap power, that is’**

The think tank Common Wealth argued in a recent report that ‘In place of a privatised system, public power, funded by lower cost financing and planned around need, would deliver a clear, secure and affordable energy future, and do so faster, cheaper and more fairly.’<sup>396</sup> The economic geographer Brett Christophers has dedicated his most recent book (*The Price is Wrong*) to the subsidy-dependency of renewables, and concludes that ‘extensive public ownership of renewable energy assets appears the most viable model’.<sup>397</sup> This sentiment has to a large extent driven the creation of Great British Energy, as previously discussed.

If we're ever going to pull our power markets back from an ever-expanding state, now is the time to be forcefully making the arguments for why markets are key to cheap energy. Thus this chapter will take that debate head-on, and make the case that Nigel Lawson's vision is still the key to cheap power. It will then discuss several of the key enablers for this vision, such as suppliers taking on an expanded role in the system.

## Why markets and demand-led growth will deliver cheaper power than central planning

Proponents of the free market believe that subsidies are inefficient (particularly if sustained indefinitely), and that the market will tend to do a better job than central procurement. But it is worth fleshing this point out – simply put, why do we think subsidy-free power stations will be cheaper in the long term than a centrally planned system of CfDs and RABs?

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396 ‘Energy – Who Owns Britain? Data Dashboard’, *Common Wealth*, 2025. [Link](#)

397 B. Christophers, ‘The Price is Wrong: Why Capitalism Won't Save the Planet’, *Verso*, March 2024.



## *Capital costs and a fixed pipeline*

First, it's worth acknowledging that CfDs absolutely do have their advantages. Most crucially they eliminate the counterparty risk that hampers PPAs – after all, central government (via the LCCC) is the ultimate risk-free counterparty. (Though whether the spectre of a Reform government that has talked about ripping up these contracts changes this calculus remains to be seen.)

Reduced counterparty risk brings lower financing costs, which means a cheaper overall 'strike price', all things being equal. As does the longer contract structure which comes with a CfD – 15 years previously, and 20 for future contracts, versus 5-15 years for PPAs.

Additionally, a fixed pipeline of renewable auctions (and a guaranteed buyer) brings predictability and stability to industry – another recipe for low costs. Indeed, it's not as if Government just hands out these contracts – each project has to compete against other projects (usually of the same technology) at auction, ensuring lower prices for consumers.

**‘ Making CfDs a permanent feature of our energy system is a recipe for inefficient central planning, distorted markets – and ultimately higher bills ’**

At the cheapest auction prices (AR4 in 2022), the winning strike prices were below wholesale prices, and still are today (£53/MWh for offshore wind vs £81/MWh average price last year, though some of this capacity was re-bid at higher prices in AR6). Meaning those contracts could be paying us back once operational – no subsidy required. Of course a fair amount of that capacity was 're-bid' in AR6 at higher prices, and subsequent auctions have not matched those lows. And in aggregate, CfDs have only paid back during the energy price crisis.<sup>398</sup>

However, while CfDs were undoubtedly a great instrument to help scale up renewables, making them a permanent feature of our system is a recipe for inefficient central planning, distorted markets – and ultimately higher bills.

### *The divine hand of DESNZ*

The first reason for this is that while CfD auctions do create competition between individual projects, they still leave DESNZ in the driver's seat when it comes to picking the overall capacity mix. The total amount of money on offer is set by Government, and this determines how many projects go ahead. In fact, given the huge amounts of capacity needed for Clean Power 2030, the Government has granted itself the ability to increase the budget for offshore wind after bids are received (and to do the same for potentially other technologies in future) – not exactly a recipe for cheap bills.<sup>399</sup>

398 'CfD Historical Data', *Low Carbon Contracts Company*, 2026. [Link](#)

399 'Further Reforms to the Contracts for Difference Scheme for Allocation Round 7: Government Response to Policy Proposals', *Department for Energy Security & Net Zero*, July 2025. [Link](#). 'Contracts for Difference for Low Carbon Electricity Generation: Consultation on proposed refinements for Allocation Round 8 and future rounds', *Department for Energy Security & Net Zero*, December 2025. [Link](#)



Moreover, these auctions are structured into different ‘pots’ based on specific technologies. In recent auctions offshore wind has had its own pot of money, different to the pot for other mature technologies like solar and onshore wind, while novel technologies had yet another pot. So while individual offshore wind projects do have to compete against each other, they do not have to compete against solar projects.

In AR6 in 2024, solar and onshore wind were ~£10/MWh cheaper than offshore wind, but offshore wind still has its own pot of funding. In fact, in that auction, offshore wind got £1,100 million, novel technologies like Tidal Stream got £270 million, while solar and onshore wind got £185 million (all figures in 2012 prices).<sup>400</sup> And this was after the new Government decided to increase the overall budget by £530 million shortly after being elected.<sup>401</sup>

**‘ Government will never have perfect information, and is always at risk of misjudging the markets or being taken for a ride ’**

Ministers will argue that pot budgets are set based on the pipeline of projects eligible, and that offshore wind is a special case, because it is seen as the backbone of the future system.<sup>402</sup> But whatever the reason, it leaves the Energy Department essentially deciding how much capacity gets built, and to a large extent which technologies make up that capacity mix.

The pitfalls of this as a long-term strategy should be plain to see. First, Government will never have perfect information, and is always at risk of misjudging the markets or being taken for a ride. Just look at the infamous failed CfD round of 2023 (AR5), where DESNZ set the cap price too low and the auction received no bids for offshore wind. Wind farm developers had been warning for months that the price was too low – but the Department evidently thought they were crying wolf.<sup>403</sup>

This approach also assumes that the state is doggedly seeking the cheapest power mix for consumers, when of course other priorities often get in the way. Just look at the requirement (introduced by the Conservatives, but bolstered by Labour) for offshore wind projects bidding into the CfD to fund a ‘Clean Industry Bonus’ alongside their CfD. Bidders have to invest a minimum of £100m per GW in manufacturing facilities, ports and the like in deprived areas or sourcing from particularly ‘green’ suppliers for their kit – and further investments beyond this minimum will also be considered.<sup>404</sup>

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400 ‘Contracts for Difference: Budget Revision Notice for Sixth Allocation Round’, *Department for Energy Security & Net Zero*, July 2024. [Link](#)

401 Ibid.

402 ‘Contracts for Difference: Allocation Round 4 FAQs’, *Contracts for Difference (CfD) Allocation Round Resource Portal*, January 2022. [Link](#). ‘Allocation Round 6 (AR6) will feature three auction pots, with offshore wind in its own auction pot. This change reflects the large pipeline of offshore wind expected this round and the strength of competition amongst established technologies in Pot 1’. ‘Clean Power 2030 Action Plan: A New Era of Clean Electricity’, *Department for Energy Security & Net Zero*, May 2025. [Link](#)

403 ‘Allocation Round 5 – Why it matters, and risks to the UK if the Government doesn’t act’, *Energy UK*, May 2023. [Link](#)

404 ‘Clean Industry Bonus or Burden?’, *Watson Farley & Williams*, March 2025. [Link](#). ‘Funding Boost for Clean Industry Bonus as Bids Smash Expectations’, *Department for Energy Security & Net Zero*, May 2025. [Link](#)



For the purposes of green jobs and levelling up, this is manna from heaven. In terms of delivering the cheapest power for consumers, it may not be. Not least because it will ultimately be funded via energy bills – and is in addition to a further £1bn to be invested by Great British Energy in supply chains, including offshore wind.<sup>405</sup> (Supporters will argue that UK supply chains will be cheaper in the long term – but if that were so, they would presumably have been set up that way in the first place.)<sup>406</sup>

This issue of political influence is obviously made worse by the Government's Clean Power 2030 goals. In its sprint to procure as much low-carbon capacity as possible – for overwhelmingly ideological reasons – the Government decided to double the budget for offshore wind in AR7. To have a chance at hitting the 2030 target, they will need to procure at least a similar amount of capacity in the next auction.<sup>407</sup> What better example could there be of politics getting in the way of the cheapest power for consumers, via the CfD mechanism?

**‘ British Steel owner Jingye was told by National Grid in 2024 that it would not be able to secure a new grid connection for its proposed electric arc furnace at Scunthorpe until 2032 ’**

#### *Future demand growth and the risk of oversupply*

This leads to a second, but related point – the central issue of what demand growth will look like.

If we take NESO's estimates, in 2030 demand will be 14% higher than in 2024; in 2035 it'll be 37% higher; in 2050 anywhere from 93% to 175% higher.<sup>408</sup> But within the industry, there is significant uncertainty, and unease, about the future.

In part this is due to grid constraints – both transmission and distribution capacity have been slow to ramp up, and many demand-side projects face the same issues with grid connections. For example, British Steel owner Jingye was told by National Grid in 2024 that it would not be able to secure a new grid connection for its proposed electric arc furnace at Scunthorpe until 2032 – arguably contributing to the later nationalisation debacle.<sup>409</sup> Ditto for data centres, EV charging hubs, and the like.<sup>410</sup>

But the main point is that the pace of the energy transition is looking uncertain at the moment. The Government is sending decidedly mixed signals on EVs (re-starting the plug-in grant while softening the ZEV mandate), and while heat pump installations continue to grow (to almost 60,000 in 2024), we are very far off the previous

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405 'Powering Britain's Future', *Department for Energy Security & Net Zero*, June 2025. [Link](#). 'Further Reforms to the Contracts for Difference Scheme for Allocation Round 7: Consultation Document', *Department for Energy Security & Net Zero*, July 2025. [Link](#)

406 Funding boost for Clean Industry Bonus as bids smash expectations', *Department for Energy Security & Net Zero*, May 2025. [Link](#)

407 M. Lempriere & S. Evans, 'Q&A: What UK's record auction for offshore wind means for bills and clean power by 2030', *Carbon Brief*, January 2026. [Link](#)

408 Per FES 2025. Note the 2030 and 2035 figures use the 10 Year Forecast (NESO's best expectation), but the full range is 12%-19% for 2030 and 29%-60% for 2035 (the latter both include the 'Falling Behind' scenario where Net Zero is not reached).

409 'British Steel Today Unveils £1.25bn Proposal to Decarbonise Its Operations', *British Steel*, November 2023. [Link](#). O. Gill, 'British Steel 'green' plan hit by electricity shortage', *The Times*, October 2024. [Link](#)

410 'Electricity Networks Collaborate to Accelerate Connection Timescales in West London', *National Grid*, March 2024. [Link](#)



government's target of 600,000 per year by 2028.<sup>411</sup> And that's to say nothing about the prospect of a future administration reversing all of these measures.

Most critically, the key to enabling electrification across the economy is cheap electricity – and right now our prices are anything but cheap. Thus while almost everyone interviewed for this paper believed that demand would indeed pick up eventually, over what time scale was very much a point of uncertainty.

In the post-decarbonisation era, new plants should only be coming online if there is demand to absorb the new power (meaning they will be able to sell most or all of their 'volume'). If not, the market would be sending a signal to new operators that Great Britain is oversupplied, and thus investors should take their money elsewhere. This would be markets working exactly as they should – finding the equilibrium between supply and demand.

**‘ Unlike PPAs, where generation is being built to respond directly to new sources of demand, in a CfD it is Whitehall that ultimately decides how much capacity should be built ’**

As a demonstration of this phenomenon, witness investors starting to get cold feet in Nordic markets, which have even more renewables than we do. Denmark, which generated nearly 60% of its power from wind in 2023 (the highest rate in the world), received no bids in its largest-ever tender for offshore wind last December. According to Bloomberg, 'One major turnoff is low electricity prices that are weighed down by abundant supply from existing wind farms crowding into the market.'<sup>412</sup> (The Danish auction system didn't use a revenue stabilisation model like the UK.)<sup>413</sup>

The problem here is that the CfD muffles this mechanism to a substantial extent. Unlike PPAs, where generation is being built to respond directly to new sources of demand, in a CfD it is Whitehall that ultimately decides how much capacity should be built. As mentioned above, there is every risk of getting it wrong, or being subject to political influences.

Remarkably NESO already sees oversupply in our future – the latest modelling predicts that volume curtailment (i.e. a generator failing to find a buyer for its power and thus not generating) will go from 0% today to between 3-5% of wind and solar generation in 2030, and 7-9% in 2035.<sup>414</sup>

Indeed, the latest NESO modelling acknowledges this risk directly: 'The FES 2025 Net Zero pathways reflect the government's clean power goals by 2030. However, reflecting the high volume of projects in development, they then continue high deployment of renewables and nuclear through the 2030s, at a faster pace than demand growth or the pace required to maintain clean power. This leads to higher levels of curtailment and export, which tend to add to costs of the GB system.'<sup>415</sup>

411 T. Birch, 'UK Heat Pump Target Missed Despite Surge in Installations', *The Eco Experts*, January 2025. [Link](#)

412 W. Mathis, 'Europe is Reaching a Limit to Its Wind Power Expansion', *Bloomberg*, December 2024. [Link](#)

413 S.R.C. Roy, 'WindEurope Highlights Policy Flaws as Denmark's 3 GW Offshore Wind Auction Fails', *WindInsider*, December 2024. [Link](#)

414 FES 2025, Data workbook tab F.19. Note this represents annual curtailment after DACCs, and excluding the 'Falling Behind' scenarios for these purposes

415 'FES 2025 Economics Annex', *National Energy System Operator*, December 2025. [Link](#)



In a CfD system, if generators foresee volume risk in future, they will demand higher strike prices at auction to make up for the lost generation – Energy Department officials are already incorporating this dynamic into their calculation of the cap price for CfD auctions.<sup>416</sup> (There will likely be some dynamic effects of batteries absorbing excess generation, though exactly how much is difficult to know.) So if the Government over-buys, consumers will end up being stuck with higher prices for 20 years.<sup>417</sup> If wholesale prices drop low enough throughout the year, this could even end up pushing post-contract renewables off the system, doubly harming consumers (since such power should be genuinely cheap once its subsidy contract has expired).<sup>418</sup>

The export point is also worth highlighting. As NESO mentions above, the other option during periods of oversupply is exporting to neighbouring countries. While we are currently net importers (i.e. across the year we take in more power than we export), this dynamic is expected to flip in the next few years as more renewable generation comes onstream.<sup>419</sup>

**‘ Not only will a CfD distort the economic signals for cross-border power trading, it will do so in a way that sees us subsidising the consumption of European consumers ’**

But the prospect of oversupply, combined with the mechanism of the CfD, means this could result in distorted (and costly) outcomes. In a high-wind period for example our prices will likely be low, and thus we may be exporting surplus generation to Europe. But while wholesale prices may be at rock-bottom, so long as they’re not negative, assets on a CfD still receive their full top-up. What’s more, in such periods the users of that power will be Europeans, despite British billpayers stumping up for the CfD costs. So not only will the CfD distort the economic signals for cross-border power trading, it will do so in a way that sees us subsidising the consumption of European consumers.

This further adds cost, as NESO acknowledges in its Clean Power Report. ‘As Great Britain transitions to a clean power system, it is anticipated to become a net exporter of electricity (Figure 9). However, exports will be highest during periods of high renewable energy output, which typically coincide with relatively lower prices under current arrangements (Figure 8). While exporting can help recover some costs

416 E.g. per AR6 methodology note (page 17) ‘The Department applies economic curtailment assumptions separately to the net load factor when calculating ASPs.’ ‘Contracts for Difference Methodology used to set Administrative Strike Prices for CfD Allocation Round 6’, *Department for Energy Security & Net Zero*, November 2023. [Link](#)

417 There is also a question about the Offtaker of Last Resort (OLR) scheme, which was designed to mitigate the risk of early CfD generators being unable to secure a route to market for their power, and thus facilitates backstop RtM PPAs with suppliers. As this has never been an issue, the scheme has never been used. However as Stonehaven points out, there is a risk the OLR is triggered in future if the market is oversupplied, despite the enforced £25/MWh discount if the alternative is no revenue at all. This was not the original intent of the scheme, and as made clear in the second REMA consultation the CfD is not meant to protect generators from economic curtailment risk. Thus while it’s unclear whether the OLR scheme could or would in practice be used in this way, the scheme is worth re-examining to ensure it cannot be abused in future. ‘Offtaker of Last Resort (OLR)’, *Ofgem*, 2026. [Link](#). ‘Beyond REMA: Three provocations for the future of the UK power market’, *Stonehaven*, November 2025. [Link](#). ‘Review of electricity market arrangements (REMA): second consultation’, *Department for Energy Security & Net Zero*, March 2024. [Link](#) (Page 52)

418 Several industry sources we spoke to highlighted this as a potential risk, but whether it occurs depends on the future price curve, and the operating costs of post-contract renewables, which are not yet entirely clear.

419 ‘Clean Power 2030 Annex 4: Costs and benefit analysis’, *National Energy System Operator*, November 2024. [Link](#)



compared to curtailing excess generation, significant net exports at low prices still incur some overall costs to the British system.<sup>420</sup>

Finally, the prospect of oversupply becomes even more alarming if the predicted demand uplift fails to materialise. In the demand growth forecasts from NESO, demand is modelled independently from supply, and thus assumed to be inelastic in the long-run.<sup>421</sup> In other words, NESO thinks that people will buy EVs in increasing numbers regardless of the price of electricity. But of course in reality if electricity remains expensive (a real possibility given the Government's Clean Power 2030 sprint), take-up of new electro-tech will be severely undermined.

If so, this could create a self-reinforcing cycle. If new sources of demand are not cropping up as expected, then with each year that passes more generation will be coming online with no one to take the power. And because all of these surplus renewables will be desperately chasing their subsidy and pushing lower-cost merchant projects out of the market, overall costs to consumers will remain high as a result, despite wholesale prices being low – a vicious self-reinforcing cycle. As elsewhere, it is an illustration of the risk of relying on centralised procurement and official modelling, rather than building generation to directly respond to demand.

### *Intermittency*

A third point to make is regarding the issue of intermittency. Put simply, renewable power assets going through the CfD don't have to account for the fact that they only generate when the weather cooperates.

This is a longstanding issue – to the point where Dieter Helm's official review in 2017 recommended 'firm power' auctions, which would have forced for example a wind farm to bid in alongside a battery which could compensate for its intermittency.<sup>422</sup> The idea was never implemented – the industry ultimately regarded it as an inefficient placement of risk, and we do not seek to relitigate that here.

The advantage of a PPA relative to a CfD in this instance is that the buyer of that PPA (a company) is forced to reckon with intermittency, both via the asset (or combination of assets) they choose, as well as balancing and shaping fees. In contrast, the buyer of a CfD (the state, and ultimately consumers) does not have to marry up variable renewables with firm power in the same way.

Now the Government does of course have plenty of other schemes, such as for Long Duration Storage, interconnectors, power CCUS, and so on. But none of these are joined up with each other – rather, they're all underpinned by modelling, and a bird's eye view of what's best for the system.

Which again leaves the same risk. If DESNZ is the divine hand creating the power system, there is every risk of getting it wrong or having imperfect information. Forcing the actual buyers of the new generation to reckon with the intermittency of renewables is a far better way to ensure said customer is actually getting the cheapest power.

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420 Ibid.

421 A. Bell, 'The Ghost at the Feast', *The Unbalancing Mechanism*, September 2024. [Link](#)

422 D. Helm, 'Cost of energy: independent review', *Department for Energy Security and Net Zero & Department for Business, Energy & Industrial Strategy*, August 2017. [Link](#)



### *One size fits all*

Another point to note is the rigidly standardised nature of the CfD framework. For most technologies, the key contractual terms – tenor, revenue model, treatment of curtailment, and the rules around negative pricing – are fixed and uniform across all projects within a given round. This uniformity is deliberate: it ensures comparability in the auction process and underpins a level playing field for bidders, while keeping transaction costs low. But uniformity also comes at a cost.

Renewables are not homogenous – a 50 MW solar project in Cornwall faces different generation patterns, risks and financing needs from a 3 GW offshore wind farm in the North Sea. By enforcing a one-size-fits-all structure, CfDs eliminate the ability to tailor contracts to project characteristics, creating inefficiencies both at project level and in the wider power system.

**‘ The current design of the CfD causes a number of operational and investment distortions, which the Government itself acknowledges will require ‘profound reform’ to address ’**

In the PPA market, a wide variety of contracts are possible. PPAs can vary widely in tenor – while 10-15 years is common, some can be shorter or longer depending on the buyer and asset type. Pricing structures are most commonly fixed-price, pay-as-produced, but can also be indexed to wholesale markets to share price risk, or designed with caps, collars or floors to balance exposure between the parties. More sophisticated deals can even bundle different assets – for example solar and wind, sometimes with storage – to offer a pseudo-baseload supply profile (admittedly, rare today).

While moving away from standardisation will involve higher transaction costs, it also means that contracts can be tailored to align incentives, manage risk in different ways, and better reflect the diversity of renewable generation technologies.

The point is that CfD uniformity works for auctions – it makes bids comparable and simplifies administration. But when thinking about the electricity system as a whole, and about matching contract design to the diversity of projects and technologies, that very uniformity risks inefficiency. PPAs may lack the neatness of a common template, but their flexibility allows risk and value to be shared more efficiently across different actors in the market.

### *Operational and investment distortions*

Finally, the current design of the CfD causes a number of operational and investment distortions, which the Government itself acknowledges will require ‘profound reform’ to address.<sup>423</sup>

The CfD incentivises a renewable generator to maximise output, both in design of the asset and in operational decisions. While this is rational at a project level, it can also lead to ‘various dispatch inefficiencies and higher system costs’, as the Government put it.<sup>424</sup>

423 ‘Review of Electricity Market Arrangements: Summary of responses to second consultation’, *Department for Energy Security & Net Zero*, December 2024. [Link](#)

424 Ibid.



This is because the way the CfD is structured incentivises generators to feed as much power as possible into the wholesale (day-ahead) market, even at very low prices and regardless of wider system requirements, intra-day prices or other revenue sources (such as in ancillary services). In other words, this means generators will always seek to maximise their subsidy, and thus generate in a way they never would if they were exposed to market forces.

And because generators' subsidy is tied to prices in the day-ahead market, there's little incentive for them to hedge ahead of time, contributing to lower forward liquidity.

By contrast, PPAs enable corporate customers and to some extent intermediaries/suppliers to hedge price risk over a longer time frame.<sup>425</sup> What's more, the operational distortions described above are substantially reduced, particularly for 'physical' PPAs, again via buyer and seller negotiating directly, rather than indirectly as in the CfD.

**‘ PPAs enable corporate customers and to some extent intermediaries/suppliers to hedge price risk over a longer time frame ’**

To conclude, this section has aimed to cut against the prevailing narrative that CfDs are the route to cheap power, relative to PPAs, over the medium to long term. CfDs do absolutely remove counterparty risk and provide investors with certainty, thus lowering financing costs. However, they also require DESNZ to pick winners and centrally plan the system, with all the risks of bad information and incentives that brings. They ignore the extra costs of intermittency, and distort the wholesale market in ways that will lead to inefficiencies and higher costs.

Whether all of the above factors ultimately outweigh the capital costs point is of course very difficult to know. As seen in the recent locational pricing debate, truly objective modelling can be difficult to come by, particularly while being transparent about assumptions and modelling inputs.

At the end of the day, it's a question of whether one believes that markets and companies are better placed to seek out the cheapest power, or if that job is better left to Government. The CPS remains convinced that Lawson's original vision was correct – and that we should therefore aim to move away from the CfD.

## How to wind down the subsidies

How to then do this effectively? By no means should this be an abrupt or reckless change. The move away from CfDs should be signposted to industry well in advance, with their being phased out gradually over time.

But the general principle should be that more and more new capacity should be built privately, and less and less with government subsidy (perhaps with the exception of the largest assets like nuclear and offshore wind farms of several GWs).

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<sup>425</sup> 'The Role of PPAs in Decarbonising the UK Power Grid', *Centrica*, 2024. [Link](#)



There are several ways of facilitating this. One in fact was proposed in the REMA consultation – namely ‘partial’ CfD payments.<sup>426</sup>

Under this system, new projects would not be able to bid all of their capacity into the CfD auction – rather they could take a CfD for a certain percentage, while the rest would have to operate on a merchant basis. In practice many developers would likely seek a PPA for the non-CfD portion of the asset, as is already happening today in the ‘stacked’ revenue model.

While the terms would need to be set out ahead of time to give developers time to adapt and plan, the CfD percentage could be reduced over time, eventually down to zero.

Another variation on this theme would be for the Government to set out in advance that it intends to buy a decreasing share of capacity in the CfD auctions each year. If coupled with steers to the market on roughly how much capacity the Government thinks will be needed over time, this would provide a strong signal to industry to seek alternative routes to market beyond the CfD.

**‘ We need to send a clear message to the market that renewable subsidies are on the way out and that new assets needed to stand on their own two feet, without pulling rug out from under the industry ’**

Either approach would send a clear message to the market that renewable subsidies are on the way out and that new assets needed to stand on their own two feet. But it would do so in a way that did not pull the rug out from under the industry, and gave investors and developers time to adjust.

The same principles should apply to ‘repowered’ assets (which need upgrading at the end of their useful life), rather than the current approach of letting them bid into the CfD round, and claim subsidies for years more to come.<sup>427</sup>

Undoubtedly there will be voices in industry who argue against these changes – once subsidies are put in place, removing them is always a thankless task. But if we’re serious about getting the cheapest power mix for consumers, the market needs to be in the driver’s seat – not the Energy Department.

The same of course applies to new SMRs and AMRs, though obviously they are at an earlier stage of development. While giving such novel technologies a government contract in the form of a RAB or CfD is absolutely the right thing to do now, these too should be phased out once the technologies are mature. As discussed in Chapter 5, private projects are already advancing in the UK today, and there is every reason to think that private demand from heavy industry, industrial clusters and data centres could power a nuclear revolution in the 2030s and 2040s.<sup>428</sup>

426 ‘Review of electricity market arrangements (REMA): second consultation’, *Department for Energy Security and Net Zero*, March 2024. [Link](#)

427 ‘Further Reforms to the Contracts for Difference Scheme for Allocation Round 7: Government Response to Policy Proposals’, *Department for Energy Security & Net Zero*, July 2025. [Link](#)

428 UK Parliament Industry and Regulators Committee, ‘Oral Evidence: Administrative Scheme for “On-the-Spot” Nuclear Projects’, *UK Parliament*, July 2021. [Link](#). In Q180-181 Tom Samson of Rolls-Royce SMR discusses the current need for CfDs alongside ‘increasing demand for PPA offtakes’. ‘Financing Nuclear Projects’, *The Path to a New Era for Nuclear Energy*, *International Energy Agency*, May 2025. [Link](#)



While this report has largely focused on renewables, nuclear and gas, the same principle should apply across the piste for new technologies. Batteries are already primarily being built privately today, and while for example new hydrogen and/or CCUS plants will absolutely require Government funding as they scale up, this should not become a permanent feature of our system.<sup>429</sup> Put simply, subsidies should have sunsets.

## Reforming the CfD

In addition, the Government should not leave the CfD itself untouched. While the general direction should be moving away from subsidies, there are absolutely levers the Government could pull in the interim to reform the CfD model, eliminating some of the distortions mentioned above and helping shift new CfD-backed renewables on to a more market-based footing.

The REMA consultation process proposed several approaches to reform the CfD, and while the wind seems to have been taken out of their sails by the zonal pricing wars, we believe several of them have merit.

One approach is to de-link CfD payments from metered output. Assets with a CfD would essentially receive a pot of money at regular intervals, but then have to optimise their trading strategies around making money in the wholesale and ancillary markets like any other generator.

**‘ The REMA consultation process proposed several approaches to reform the CfD, and while the wind seems to have been taken out of their sails by the zonal pricing wars, we believe several of them have merit ’**

The original approach was for a ‘deemed’ model, whereby the generation potential for any given asset would be estimated, and payments based on this estimate – however, as the consultation identified, designing the methodology would be complicated and carries the risk of gaming or overcompensation.<sup>430</sup>

Thus we favour the second approach proposed, a capacity-based CfD. In this model, generators receive fixed payments (once operational) on a £/MW basis (akin to the Capacity Market), regardless of when the asset is generating. While this offers revenue certainty to support investment decisions, it also exposes generators to price risk (and volume risk) like any other generator in the market. Thus CfD-supported assets would generate when it’s useful for the system rather than simply seeking to maximise their subsidy, while supporting ancillary markets and encouraging forward trading. New projects would also be incentivised to minimise capex spend on projects, minimising system costs.<sup>431</sup>

Obviously in this model the value for money depends on the level of the capacity payment, and thus how much of the asset’s annualised capital cost developers would demand from the payment versus seek out in the market. That said, the model

429 Regarding batteries, while they can and do participate in the Capacity Market, most of their revenues come from other sources (see e.g. [here](#)). Meanwhile longer-duration storage assets will have the new cap and floor subsidy scheme as they scale up

430 ‘Review of Electricity Market Arrangements – Second Consultation Document’, *Department for Energy Security & Net Zero*, May 2024. [Link](#)

431 The consultation options assessment points out that developers will need sufficient visibility on likely revenues across markets for this to work well.



is far simpler to understand than the deemed one above, and given the existing familiarity with this model (e.g. in the Capacity Market) there is every reason to expect robust competition. The REMA consultation also suggests a cap to protect consumers in the event of high wholesale prices, which would be a sensible precaution.

This reform would expose generators to market signals and thus reduce the distortions created by the current CfD model, helping to lower system costs. The model obviously requires further work to develop, though it has support in the industry from the likes of Centrica and the Association for Decentralised Energy (Energy UK is open to it but expressed a preference for the deemed model).<sup>432</sup> The Government has said that no changes to the CfD would be introduced until AR9 at the earliest (in 2027), and lead-in time is helpful for the industry to prepare.<sup>433</sup> However, we would urge them to be bold, and de-link future CfD payments from output.

**‘ The Government has said that no changes to the CfD would be introduced until AR9 at the earliest (in 2027), and lead-in time is helpful for the industry to prepare ’**

Another useful change the Government could make is re-adding offshore wind to the ‘mature’ auction pot, to create a truly technology-neutral auction (as existed in AR5). While this would still leave DESNZ setting the overall auction budget, it would at least ensure that all technologies are competing on a level playing field for the same money, and that consumers are getting the best deal. (Though it is sensible to keep a much smaller pot for nascent technologies who will not be able to compete with the mature ones.)

While this change would reduce the ability of DESNZ to centrally plan the system, it would need to be delivered with care. The risk of combining all technologies into one auction is that the more expensive technologies end up dragging up the price of the cheaper ones, given the auction is structured as pay-as-clear (i.e. the most expensive project sets the price for the entire auction).

However, DESNZ introduced an innovative method to counteract this in AR6, whereby different technologies still compete for the same pot of funding – but retain technology-specific clearing prices.<sup>434</sup> That way all technologies are on a level playing field, but there isn’t a risk of unnecessarily high strike prices for technologies which don’t need it.

While both of these changes would help re-orient the CfD in a better direction, and could be implemented in the near term, many of the underlying issues would remain. DESNZ would still be deciding how much capacity to ‘buy’ via setting the auction budget, subject to all of the same political influences, and independent of the various other subsidy programmes. It still socialises risk that should be put in the private sector and creates an inefficient system overall. Thus these changes should be seen as necessary but not sufficient – and subsidy-free should still be the direction of travel.

432 A. Rees, ‘Review of electricity market arrangements (REMA): second consultation’, *Centrica*, May 2024. [Link](#)  
‘DESNZ Review of Electricity Market Arrangements’, *The Association for Decentralised Energy*, May 2024. [Link](#)  
‘Energy UK response to Review of Electricity Market Arrangements: second consultation’, *Energy UK*, May 2024. [Link](#)

433 ‘Review of electricity market arrangements (REMA): autumn update, 2024’, *Department for Energy Security & Net Zero*, December 2024. [Link](#)

434 This is through the use of budgetary maxima for each technology which are set at the level of the total pot budget. Thus while all of the bids are ranked as normal (ensuring the cheapest win out), the algorithm then calculates a technology-specific clearing price, so that the winning strike price of cheaper technologies is not dragged up by more expensive ones.



## Suppliers are the natural actors to shape the new energy system

In today's market, both new renewables and new nuclear need a guaranteed price to be able to stand up new capacity, whether via CfD, RAB or PPA. This paper has attempted to push back on the narrative that only Government can provide such a price guarantee – indeed, corporates up and down the country have proven that completely wrong.

However, there is another set of actors in the system that is even better placed than corporates to help new demand stand up over the longer term – energy suppliers themselves. These companies are literally in the business of buying and selling energy – something not even the most sophisticated corporate buyer can say.

The basic business model of any supplier is to procure energy (through a variety of means) and then sell it on to their business and domestic customers. They can predict future prices, make decisions on what they think the cheapest capacity mix will be, and how best to sell that on to their customers better than anyone – especially Government.

**‘ In today's market, both new renewables and new nuclear need a guaranteed price to be able to stand up new capacity, whether via CfD, RAB or PPA ’**

While individual corporates will account for substantial additional demand in future in their own right (from electric arc furnaces, or green hydrogen for example), much of that increased demand is likely to come from households, via EVs and heat pumps. And while there are some models of individuals taking a direct stake in their energy procurement (via community energy projects), most households simply want a cheap contract from a supplier. Indeed, it's precisely the huge buying power of suppliers (amalgamated across many households and businesses) that makes them such powerful actors.

So to our minds, suppliers have a much larger role to play in the vision of energy abundance over the longer term.

What's particularly remarkable (and little discussed today) is that this vision was an option on the table in the first REMA consultation in 2022. Then, it was referred to as a 'supplier obligation'. Rather than the Government deciding what capacity to buy via the CfD, it would simply tell suppliers that they needed to source an increasing percentage of their power from clean generation, and let them work out how to do so.

While it was predictably rejected for being too radical, the consultation itself lays out the case for it brilliantly and is worth quoting in full:

'A decarbonisation obligation offers advantages which few other options under consideration can match. Most importantly, investment decisions are market-driven. This reduces the risk of the government making inefficient decisions about the future capacity mix, and maximises the potential for cross-technology competition.



'This differs from past measures, including the Renewables Obligation scheme, as suppliers have more freedom as to how they meet their obligation, rather than having to procure from Ofgem-accredited plants. They would therefore play a key part in decisions about the capacity mix, and would create more direct incentives for smaller-scale and demand-side flexibility, and electricity demand reduction.

'This would also create more incentives for innovation, both in terms of technologies and business models, which will be critical to least cost decarbonisation. An obligation could also send more effective locational signals, as generation assets could be rewarded for building in locations which best matched suppliers' demand profile.'<sup>435</sup>

This vision is still compelling and relevant today. And it is profoundly depressing that a centre-right Government put this option on the table, then decided against it for being too bold.

Indeed, as a template for the future system the supplier obligation is even more compelling today. With the system largely decarbonised by the 2030s, no 'obligation' would be necessary – suppliers would simply need to source power for their customers as they saw fit.

It's worth noting, of course, that the consultation saw two pitfalls with this option. The first was counterparty risk, which this paper has discussed extensively and our proposal of a PPA Guarantee Facility is designed to help alleviate. The second was delivery risk – namely whether suppliers could be trusted to manage all of the investment required – which we turn to next.

**‘ It is profoundly depressing that a centre-right Government put a bold reform like ‘supplier obligation’ on the table, then decided against it for being too bold ’**

## How to transition to a model where suppliers take on more responsibility

What would need to happen in order to make this vision a reality at some point in the 2030s?

It's worth remembering that in today's market suppliers are happy to sign PPA deals with generators – but rarely without a 'back-to-back' agreement with a corporate customer, which effectively removes the price risk from their books.

Yet while corporates are the main drivers of the PPA market today, the universe of buyers willing to take on a PPA is inherently limited, to say nothing of households who cannot do so on their own. If PPAs are ultimately to replace CfDs as the primary method for standing up mature renewables, this will have to change.

Why is this so rare in today's market? At its most basic, suppliers face a mismatch in time horizons – while they would be locking in power prices for 10+ years with a

<sup>435</sup> 'Review of Electricity Market Arrangements', *Department for Business, Energy & Industrial Strategy (BEIS)*, October 2022. [Link](#)



new solar farm or SMR, on the domestic side fixed contracts are typically 1-2 years, while business contracts last 5 years at most.<sup>436</sup> Relative to a corporate client who elects to take on that price risk for 10-15 years, a supplier still has to sell power on to a customer at whatever the market rate is. So if power prices plunge after signing a PPA contract, the supplier is in a tight spot – either maintain high prices and lose customers, or drop prices to match the market and lose money on the contract.

However, it's worth remembering that suppliers have been able to manage this risk in the past. In the pre-CfD era, utilities commonly took on PPAs with price risk for new renewable assets under the Renewables Obligation scheme. Generators did not receive fixed prices as they do in the CfD, and thus needed a 'bankable' PPA from a utility or aggregator, which often included a price floor alongside a 15-year contract.<sup>437</sup>

Admittedly, the appetite to take on long-term price risk started to decline in the early 2010s, and the advent of the CfD of course removed the need for such contracts, by transferring the price risk from generators and suppliers to consumers. But the point is that suppliers taking on price risk is not a completely new phenomenon.

**‘ If power prices plunge after signing a PPA contract, the supplier is in a tight spot – either maintain high prices and lose customers, or drop prices to match the market and lose money on the contract ’**

Moreover, this model does exist to some extent in today's market. '100% green' suppliers such as Good Energy advertise that they use their customers' demand to help stand up new sources of generation. In 2022-23 nearly 60% of the power Good Energy bought was from new-build generators, and 40% of the generators they contract with are unsubsidised.<sup>438</sup> And while in 2021 they publicised a five-year solar PPA they had signed, their home and business tariffs are fixed for one or two years at most.<sup>439</sup>

This type of arrangement should be easier for vertically integrated suppliers who own their own sources of generation alongside supplying customers, such as EDF, Scottish Power, and Ecotricity. All the more so for larger suppliers with the balance sheet capability to finance the assets themselves. While this is obviously not the dominant paradigm today (not least because many of today's large suppliers are not vertically integrated), it at least points to the building blocks for such a model in the future.

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436 'Set up a business energy contract', *Ofgem*, 2025. [Link](#)

437 Baringa, 'Power Purchase Agreements for Independent Renewable Generators – An Assessment of Existing and Future Market Liquidity', *Department of Energy & Climate Change*, July 2013. [Link](#). 'Offtaker of Last Resort: Impact Assessment', *Department of Energy & Climate Change*, June 2014. [Link](#)

438 'All about Good Energy's Standard Variable Tariff', *Good Energy*, February 2024. [Link](#). 'Good Energy Completes Sale of Wind and Solar Farms', *Good Energy*, January 2022. [Link](#). See this example of a five year PPA with a 3.5 MW solar farm. 'Good Energy Signs New Subsidy-Free Solar Power Agreements', *Good Energy*, February 2021. [Link](#)

439 'Good Energy Tariffs', *Good Energy*, 2025. [Link](#) (home tariffs for heat pumps and EVs are 12 month fixes) 'Good Energy Business Energy Rates and Tariffs', *Business Energy UK*, 2025. [Link](#)



However, there are a number of other impediments on the supply side. One is that the domestic market is currently constrained by the energy price cap.<sup>440</sup> Such rigid price controls are damaging for competition more widely. But the cap itself also acts as a barrier to longer-term deals. That's because it distorts trading and hedging for power. Suppliers are incentivised to trade power in line with the (short-term) cap methodology, and disincentivised from seeking to gain an edge in trading or be innovative with their hedging strategy.<sup>441</sup>

The price cap also contributes to a wider lack of forward liquidity. In today's market, trading power more than two years ahead is difficult – meaning suppliers who take on long-term contracts (without a long-term source of demand behind them) don't have the tools to hedge and trade this risk effectively.

The price cap is not the only contributing factor – responses to an Ofgem consultation in 2024 on the subject also highlighted the CfD scheme, the suspension of the previous Market Maker Obligation scheme, as well as other wider factors.<sup>442</sup> Thus while reforming CfDs and scrapping the price cap would both help, strengthening liquidity in the forward market is a wider issue that needs to be gripped.

**↳ In 2022-23 nearly 60% of the power  
Good Energy bought was from new-build  
generators, and 40% of the generators  
they contract with are unsubsidised**

There is also a point around volatility and risk appetite. Particularly after the energy crisis, where a number of suppliers went bust, the industry will naturally be cautious about taking on longer term price risk and thinking about novel strategies. All the more so given how tightly regulated the market is. And the market is set to undergo profound changes in the next decade, with a changing generation mix making forecasting more difficult.

That said, the contours of the new landscape should start to come into view in the next few years, especially if the Clean Power 2030 pace is maintained. Moreover, if Government gave a clear steer that CfDs were not going to be a permanent feature of the market, it would incentivise suppliers to seek out new sources of generation to meet rising demand – as suppliers did under the Renewables Obligation scheme. Similarly, it would signal to regulators that the Government wants suppliers to take a more active and risk-taking role in the market, helping to re-orient the regulatory regime.

A final piece of the puzzle is the greater use of longer-term contracts on the demand side. Chapter 4 detailed how larger corporates are taking on PPAs that act as a hedge for a portion of their power supply over the longer-term. As more businesses become familiar with these sorts of contracts, this trend could well increase. Indeed, suppliers today tend to offer businesses cheaper prices for a fixed-term deal, in the same way as domestic contracts.<sup>443</sup>

440 D. Smith, 'The Case Against the Energy Price Cap', *Centre for Policy Studies*, August 2023. [Link](#)

441 G. Anstey & M. Martinsen, 'Assessing the Cost of Hedging Under the Current Default Tariff Cap', *NERA Economic Consulting*, February 2024. [Link](#)

442 'Summary of Responses Following Liquidity Call for Input', *Ofgem*, August 2024. [Link](#)

443 T. Melhuish, 'A complete guide to business energy contracts', *AquaSwitch*, n.d. [Link](#)



While obviously no business should be forced into taking on longer-term contracts, as the PPA market ramps up one could imagine suppliers offering even cheaper prices for longer-duration supply deals (particularly if exempted from CfD levies for that portion of demand), and using these to offload some of the PPA price risk.

Meanwhile, on the domestic side, fixed-term deals are usually between one and two years.<sup>444</sup> But in the future, might some households be persuaded to take on a longer-term contract, particularly if it meant a cheaper deal on their power?

In the mortgage market, fixing for longer is relatively commonplace, typically for either two or five years but including up to 10 years.<sup>445</sup> But this is not some natural law: in the US for example mortgages have fixed rates for up to 30 years. In the home solar market, subscription services (to repay the cost of panels and batteries) can last for 20 years.<sup>446</sup> And in the same way that mortgages can be ported to a new house when moving, there's no reason why a longer-term energy deal couldn't do the same.<sup>447</sup>

**‘ In the mortgage market, fixing for longer is relatively commonplace, typically for either two or five years but including up to 10 years ’**

Of course, any individual household is a tiny source of demand, but aggregated across many thousands of households a supplier would have a substantial amount of demand to put to work. This is even more the case in the context of rising demand for EVs and heat pumps, which is expected to drive a large bulk of the new generation required. We are already seeing innovative service offerings where suppliers and car companies partner to offer a combined package of EV leasing and energy.<sup>448</sup> And EV leases tend to be anywhere from two to five years – so might energy suppliers use this new source of longer-term demand to procure the cheapest new generation for their customers?<sup>449</sup>

Obviously, this is to a large degree blue sky thinking about what future business models might be profitable, and in no way should suppliers be forced into offering longer-term tariffs to consumers and businesses if it is not viable. It is simply to suggest that the current relatively short-term market on the demand side need not be permanent, and that other models are possible.

There is a final point worth discussing – the fear that CfDs could potentially undermine future private investment into new generation (in yet another way). There is a genuine worry in the industry that CfDs could essentially destroy the wholesale market as a meaningful price discovery mechanism, making future investments based on it precarious.

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444 'Fixed Price Energy Tariffs', *MoneySuperMarket*, 2025. [Link](#)

445 A. Gair, 'How Long Should I Fix My Mortgage For?', *Tembo*, August 2025. [Link](#)

446 T. Saunders, 'Sunsave Raises £113m to Install Solar Panels on Homes', *The Times*, July 2025. [Link](#)

447 'Selling a House While in a Fixed Rate Mortgage', *Online Mortgage Advisor*, 2025. [Link](#)

448 N. Goodwin, 'Unlock a Year's Free EV Charging with E.ON Next and Select', *Select Car Leasing*, March 2025. [Link](#). 'Octopus & BYD Turbocharge EV Revolution with All-Inclusive Car and Charging Bundle', *Octopus Energy*, June 2025. [Link](#)

449 'A Guide to Leasing', *Octopus Electric Vehicles*, March 2025. [Link](#)



As mentioned, CfDs were designed to be a temporary bolt-on to the market, rather than essentially replacing it. But if the market becomes saturated with renewable CfD generation which can bid zero but receive its full strike price outside of the market (via the CfD top-up), then the nightmare scenario is of very low or zero prices for much or most of the year, when CfD generation sets the price, alongside much higher prices in the hours when renewables' output is low – feast or famine.<sup>450</sup>

This is especially plausible if the Government keeps ploughing ahead with ever-larger CfD auctions in pursuit of its 2030 target and saturates the market. Suppliers would be reluctant to sign PPAs for new generation, at least for renewables, because it would be cheaper to simply buy power on the wholesale market when prices were ultra-low, while the wider costs of CfDs were socialised amongst all consumers. If this scenario is allowed to happen, the very existence of CfDs will bolster the case for keeping them, because building generation without them will be too difficult.

**‘EV leases tend to be anywhere from two to five years – so might energy suppliers use this new source of longer-term demand to procure the cheapest new generation for their customers?’**

However, this nightmare is not inevitable. For starters, rising demand (should it come...) will have an uplifting effect on wholesale prices. BloombergNEF sees a ‘U-shaped’ curve out to 2050, with declines to 2035, followed by a slow and steady rise thereafter.<sup>451</sup> And in a perfect world, once prices get to a level where it is cheaper to source new capacity than buy it on the wholesale market, suppliers should do so.

But at the moment the incentives are not set up this way – because of how the CfD is funded. Right now, the ‘supplier levies’ that fund the scheme are simply divided up by the market share of each supplier.<sup>452</sup> While this is a simple way to allocate costs, the indirect effect is that suppliers do not care about how much or how little CfD generation they source – they (and their customers) will pay the same regardless. If what suppliers paid was more closely tied to what they actually used, the incentives would change.

Operationalising this change while staying within the confines of the legal boundaries of the scheme is of course a challenge. However one method of doing so would be to let suppliers opt out of green levies for new generation they source via PPAs. Suddenly, suppliers would have an incentive to compare what they are paying in terms of wholesale and CfD costs versus a PPA with a new generator. When the latter was cheaper, they would be incentivised to sign the deal. Suppliers who were reluctant to move would be undercut by innovative rivals who could buy cheaper power, and pass the savings on to customers.

Obviously, there are wider issues with suppliers taking on long-term price risk, as discussed above, but this change would provide the key economic incentive needed to move the market.

450 Note this section is primarily discussing the existing and near-future ‘book’ of CfD contracts that function with the existing model, rather than the capacity-based CfD as suggested above.

451 ‘UK Power Market Outlook 2024: U-Shaped Prices’, *BloombergNEF*, November 2024. [Link](#)

452 ‘G16 – Supplier CfD and Nuclear RAB Payments’, *EMR Settlement & Low Carbon Contracts Company*, January 2026. [Link](#)



There would of course be losers, in particular older CfD generators who might find themselves failing to find a buyer for their power more often. But the CfD as a mechanism never guaranteed volumes – it only insulated the generator from price risk, assuming they could find a buyer.

**‘ There are a number of reasons why suppliers are reluctant to play a larger role in standing up new generation. However, none of these challenges is insurmountable ’**

There are of course more radical solutions to these issues, both as proposed in the REMA consultation (such as a split market or green power pool), and as proposed by Richard Tice (ripping up the AR7 contracts). But the former were dismissed as unworkable and the latter would have a terrible effect on investment, should it even be legally possible. Thus this change would create better incentives for new private investment, while still staying within the confines of the existing framework.

To sum up: there are a number of reasons why suppliers are reluctant to play a larger role in standing up new generation. Demand tends to be short-term, the price cap constrains innovation, forward liquidity is low, and the current market is relatively risk-averse. However, none of these challenges are insurmountable, particularly if the time horizon is the 2030s rather than the next few years. The fact that suppliers did in fact play this role in the pre-CfD era is encouraging. And if Government set this vision as its medium-term objective, and gave suppliers enough time to adjust while reforming the CfD levy as described above, there is no reason to think it should not be achievable once more.



# Conclusion

Britain's electricity system is at a crossroads. We face a choice between two competing visions: one in which the state continues to plan, subsidise and ultimately distort the system; and one in which markets are allowed to flourish, consumers are empowered, and abundance rather than scarcity becomes the lodestar of policy.

Despite years of subsidy-driven policy, our households pay some of the highest electricity prices in the West, our industries are fleeing abroad, and we remain locked into a cycle where state intervention begets more state intervention. Labour's Clean Power 2030 plan epitomises the danger: an ideological sprint to arbitrary targets, based on flawed assumptions, likely to raise costs without delivering the promised consumer savings. Great British Energy, likewise, is less a coherent solution than a reflexive expansion of state power.

**‘ Only a market-led system, responsive to signals of demand and disciplined by competition, can hope to deliver the volume of new capacity at the lowest cost ’**

And yet, the picture is not one of despair. Contrary to the entrenched assumption that the market has died a quiet death, the reality is that Britain already has a strong market for subsidy-free generation. Via the expanding corporate PPA sector, companies are proving that cheap, clean power can be built without taxpayers and billpayers underwriting every megawatt. Globally the PPA market has doubled in just a few years, and despite some challenges in 2025 the UK is well positioned to capitalise further on this trend. This is proof positive that the market can deliver — if the state would only step aside and allow it to.

Looking forward, we are entering a new era. For the past two decades, Britain has been decarbonising alongside a shrinking demand base. But with electrification of transport, heating and industry, demand is likely to surge. This will necessitate yet more generation of every type, all across the country.

But for that to happen, cheapness will be paramount. If power is not affordable, consumers will not electrify; and without electrification, progress will stall. Only a market-led system, responsive to signals of demand and disciplined by competition, can hope to deliver the volume of new capacity at the lowest cost.

The best path is therefore clear. We should not abandon renewables, but force them to stand on their own two feet. We should embrace nuclear, while clearly setting the expectation that SMRs do the same once they mature. We should trust corporates and suppliers to contract for the energy they need, rather than allowing civil servants to dictate every detail of the system. And we should reaffirm Nigel Lawson's vision: that markets are best placed to deliver the cheapest power for consumers.



The choice is between central planning and competition; between scarcity and abundance; between decline and growth. If we are serious about restoring Britain's competitiveness, re-industrialising our economy and lowering bills for households, then the answer must be competition, not coercion. It is time to return power to the markets.



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